STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Central Illinois Public Service Company (AmerenCIPS) and Union Electric Company (AmerenUE)	:	**02-0798**
Application for entry of protective order to protect confidentiality of materials submitted in support of revised gas service tariffs.	:	
Central Illinois Public Service Company	:	**03-0008**
Proposed general increase in natural gas rates.	:	
Union Electric Company	:	**03-0009**
Proposed general increase in natural gas rates.	:	**(Consolidated)**

**INITIAL BRIEF OF THE STAFF OF
THE ILLINOIS COMMERCE COMMISSION**

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INITIAL BRIEF OF THE STAFF OF
THE ILLINOIS COMMERCE COMMISSION

Pursuant to 83 Ill. Adm. Code 200.800, Staff of the Illinois Commerce Commission ("Staff"), by and through its attorneys, hereby files its Initial Brief in the above-captioned proceeding.

I. BACKGROUND; PROCEDURAL HISTORY; NATURE OF OPERATIONS; TEST YEAR

A. Background

Pursuant to Article IX of the Public Utilities Act ("Act"), on November 27, 2002, Central Illinois Public Service Company d/b/a AmerenCIPS ("CIPS" or "Company") and Union Electric Company d/b/a AmerenUE ("UE" or "Company") (jointly, "Companies", "AmerenCIPS/UE" or "Ameren") filed with the Illinois Commerce Commission ("Commission" or "ICC") tariff sheets setting forth the Companies' proposals to increase base rates for natural gas service. These proceedings were designated as Docket Nos. 03-0008 and 03-0009, respectively. The tariff filings were accompanied by direct testimony. The proposed rates for CIPS were designed to increase the Company's annual natural gas operating revenues by approximately $16.4 million, exclusive of applicable revenue related taxes, an increase of about 8.7%. The proposed rates for UE were designed to increase the Company's annual natural gas operating revenues by approximately $3.8 million, exclusive of applicable revenue related taxes, an increase of about 21.7%.

On November 27, 2002, AmerenCIPS/UE also filed an Application For Protective Order to protect the confidential nature of certain information and data contained in the direct testimony and schedules filed in support of the revised gas service tariffs. This proceeding was designated as Docket No. 02-0798.

The Commission entered a Suspension Order on January 8, 2003 and a Resuspension Order on April 23, 2003.

B. Procedural History

Pursuant to proper notice, a Prehearing Conference was held in this matter before duly authorized Administrative Law Judges of the Commission in Springfield, Illinois on January 28, 2003. At the Prehearing Conference, the three dockets were consolidated in the interest of efficiency. In addition, the Application For Protective Order was granted. A schedule was also set which provided for the filing of Staff and

Intervenor direct, Company rebuttal, Staff and Intervenor rebuttal and Company surrebuttal testimonies as well as hearings and Initial and Reply Briefs.

Petitions to Intervene were filed by the People of the State of Illinois, by the Attorney General ("People" or "AG"), the Citizens Utility Board ("CUB"), Business Energy Alliance and Resources, L.L.C. ("BEAR"), and MidAmerican Energy Company ("MEC"). All Petitions to Intervene were granted. Evidentiary hearings were held at the Commission's Springfield offices on July 7 through July 10, 2003. Appearances were entered on behalf of AmerenCIPS/UE, the People, CUB, BEAR, MEC and Staff. Thomas R. Voss, Jimmy L. Davis, Michael G. O'Bryan, Kathleen C. McShane, Thomas G. Opich, Nagendra Subbakrishna, Gary S. Weiss (adopting the testimony of Robert J. Kenney), Dan Danahy, Philip B. Difani, Jr., Jon R. Carls, Mark C. Lindgren, David Cross, Dottie R. Anderson, Laurie H. Karman, and C. Kenneth Vogl provided testimony on behalf of CIPS and UE. Burma C. Jones, Carolyn L. Bowers, Theresa Ebrey, Eric Lounsberry, Charles C.S. Iannello, Michael McNally, and Peter Lazare provided testimony on behalf of Staff. BEAR witness Lee Smith, the People's witness David J. Effron, CUB witness Richard A. Galligan and MEC witness Corey G. Jansen also provided testimony. At the conclusion of the July 10, 2003 Hearing, the record was marked "Heard and Taken".

C. Nature of Operations

CIPS and UE own and operate natural gas distribution systems in Illinois.

D. Test Year

The Companies proposed an historical test year ending June 30, 2002, with known and measurable changes. No party objected to the Company's proposed test year.

II. RATE BASE

A. Introduction

Schedules showing the Company's rate base at present and recommended rates for the test year ending June 30, 2002, were presented by Company and Staff witnesses. Staff and several intervening parties proposed a number of adjustments to the Company's proposed rate base, as discussed below.

B. Uncontested Issues

1. Gas Plant Held for Future Use

Staff witness Bowers proposed an adjustment to remove Future Use Plant from AmerenCIPS' rate base. (ICC Staff Exhibit 2.0, Schedule 2.1 CIPS.) The adjustment was accepted by the Company in its rebuttal testimony. (AmerenCIPS/UE Exhibit No. 14.0, p. 2.) The Commission need take no action on Future Use Plant as the adjustment has been incorporated into both Staff's and the Company's revenue requirement.

2. Depreciation Policy

Ameren witness Weiss proposed amortizing Accounts 391 "Office Furniture and Equipment", 394 "Tools, Shop and Garage Equipment", and 395 "Laboratory Equipment", rather than depreciating them. (AmerenUE Exhibit No. 7.0, p. 5; AmerenCIPS Exhibit No. 7.0, p. 5.) Staff witness Bowers disagreed with the

Companies' proposal based on the requirement to maintain property records so as to show the number and cost of the various record units or retirement units by Gas Plant Instruction 11C, Work Order and Property Record System Required of the Uniform System of Accounts for Gas Utilities Operating in Illinois, 83 Ill. Adm. Code 505. (ICC Staff Exhibit 2.0, pp. 3-4.) The Companies accepted Staff's position that the accounts be depreciated rather than amortized. (AmerenCIPS/UE Exhibit No. 14.0, p. 3.) Therefore, the Commission need take no further action on this issue.

3. Original Cost Determination

Staff witness Bowers proposed that the AmerenCIPS' original cost determination be as shown below. (ICC Staff Exhibit 16.0, pp. 3-4.) The amounts are from the Company's Original Filing, Schedule B-2:

Production:	$ 1,876,000
Storage:	27,847,000
Transmission:	40,935,000
Distribution:	199,133,000
	$ 269,791,000

Staff witness Bowers also proposed that the AmerenUE original cost determination be as shown below. (Id.) The amounts are from the Company's Original Filing, Schedule B-2:

Production:	$ 816,000
Distribution:	26,693,000
	$ 27,509,000

Staff proposes that the following Ordering paragraph be included in the final Commission Order:

> IT IS FURTHER ORDERED that the original cost of plant at June 30, 2002, for AmerenCIPS of $269,791,000, and $27,509,000 for AmerenUE is unconditionally approved as the original cost of plant for consideration of 83 Ill. Adm. Code 510, APPENDIX A:
>
> #12(b)(1) Journal vouchers and journal entries charging plant accounts; and
> #73 Records of predecessors and former associates.

The Companies did not contest Staff's proposed Original Cost Determinations or the proposed Ordering paragraph.

4. Richwood Storage Field

Staff continues to recommend, as it did in testimony, that CIPS remove all working capital allowance, other rate base, and expense amounts associated with the Richwood storage field from its requested rates. (ICC Staff Exhibit 4.0, pp. 18-19.) Later, Staff clarified its request to specify that CIPS should retire the Richwood storage field. (ICC Staff Exhibit 17.0 Revised, p. 23.) CIPS accepted the accounting treatment of Staff's recommendation (AmerenCIPS Exhibit No. 27.3); however, CIPS did not agree that it should be precluded from developing the field in the future and including Richwood assets in a future rate proceeding should it become used and useful. (AmerenCIPS/UE Exhibit No. 24.0, p. 17.)

On cross-examination, CIPS and Staff reached agreement by noting Staff could accept the retirement of Richwood for ratemaking purposes with the understanding that the facility is not physically retired and that AmerenCIPS would not request rate recovery for the field in the future unless there is a change in the status of the field. (Tr.,

p. 521.) Further, should CIPS chose to put the field back into service, CIPS would be required to justify any rate impact that action might have on customers. (Id., pp. 521-522.) ICC Staff Exhibit 16.0, Schedule 16.3, reflects this agreement and makes the necessary adjustments to Plant in Service, Accumulated Depreciation, Depreciation Expense and Operating Expense.

C. Contested Issues

1. Post-test Year Capital Additions

The Companies proposed pro forma adjustments to plant in service for both CIPS and UE for known and measurable changes to be completed within one year of the filing of tariffs in accordance with 83 Ill. Adm. Code 285.150. (AmerenCIPS/UE Exhibit No. 14.0, p. 5.) AG witness Effron opposed the Companies' pro forma adjustments to increase rate base for post-test year capital additions in their entirety because based on his analysis, while gross plant has increased, net plant in service has decreased during the period 1998 through 2001. (AG Exhibit 1.0P CIPS; AG Exhibit 1.0P UE.) The Companies' rebuttal testimony portrays AG witness Effron's disallowance of the pro forma adjustment as an attempt to treat Ameren's historical test year as a future test year. (AmerenCIPS/UE Exhibit No. 27.0, p. 3.)

Staff was unable to offer testimony regarding the issue. At the July 8, 2003 Hearing, counsel for the People attempted to cross-examine Staff witness Bowers regarding post-test year capital additions. Ameren's objection was sustained and she was not allowed to offer her opinion regarding the issue. Staff believes that it was error not to have permitted the cross-examination. As a result, the Commission will not have a full and complete record before it on which to base its decision.

2. Cash Working Capital Allowance

Staff witness Ebrey proposed adjustments to disallow in entirety the Companies' requested cash working capital ("CWC") requirements since the lead/lag studies offered as support are significantly flawed. (ICC Staff Exhibit 10.0, p. 3.) The Companies mistakenly believe that the lead/lag studies presented in surrebuttal testimony incorporate all but one of Staff's recommendations and that only one item, the Purchased Gas Adjustment ("PGA") revenue lag, remains a contested issue. (AmerenCIPS/UE Exhibit No. 31.0, p. 3.) However, in addition to the PGA revenue lag, two very significant items remain at issue: (1) the fuel expense lead that is supported by non-gas related invoices, gas invoices for a different company, invoices that Ameren has not provided to Staff, and invoices that total more than the total jurisdictional test year gas costs; and (2) the expense lead time for fuel expense and other operations and maintenance expense that could not be supported by the Companies. In addition, the application of the mid-point theory and the lack of recognition of Service Company involvement with cash flow remain concerns of Staff in the Companies' most recent lead/lag studies submitted in surrebuttal testimony. (Tr., pp. 467-468.)

a. Disallowance of a separate PGA revenue lag

Staff's position has, throughout the proceeding, remained that a separate lag for PGA revenues is inappropriate. (ICC Staff Exhibit 10.0, p. 6.) Staff made the following points supporting the disallowance of a separate PGA revenue lag in the lead/lag studies:

1. There is no difference in the lead-time of the receipt of PGA revenues and base rate revenues. Cash associated with PGA revenue is collected from ratepayers at the same time as cash associated with base rate revenue.

2. The Companies' support for a difference in lead-time caused by the PGA mechanism is not supportable. The PGA mechanism matches **revenue** recorded on the books of the Companies with expenses recorded by the Companies; it does not have any relationship to **cash** flows.
3. The amounts used by the Companies to determine their PGA revenue lags are inappropriate because the PGA revenues are double-counted. The amounts used from the PGA monthly filings include "true-ups" in addition to the monthly PGA revenues in the calculations.

i. Cash collected from ratepayers

The Companies define the revenue lag as the time that passes between provision of service and payment for that service. (AmerenCIPS/UE Exhibit No. 31.0, p. 2.) Company witness Subbakrishna admits that the bill for services to ratepayers includes both base rates and PGA charges (Tr., p. 377) and that any ratepayer sends only a single check including payment of both base rate and PGA charges. There is no difference between the time cash is collected for base rates and cash is collected for PGA rates for services rendered in any given time period. Thus, no separate PGA revenue lag should be considered in the calculation of the revenue lead days.

ii. PGA mechanism matches revenues and expenses

The Companies argue that there are two separate lags related to the full recovery of gas costs and that both the lags for base rate revenue and PGA revenue should be considered in a lead/lag study for CWC. (AmerenCIPS/UE Exhibit No. 17.0, p. 7.) Company witness Subbakrishna agreed that the recoveries considered in the PGA filings represent revenues recorded by the Companies. (Tr., p. 375.) While Mr. Subbakrishna admits he is not an expert accounting witness, he says he understands **cash** and his testimony is about **cash.** (Id., p. 376.) It is inappropriate to use PGA monthly filings for the analysis of a PGA revenue lag because the revenues recorded by the Companies and presented on the PGA filings are impacted by "unbilled" revenues (Tr., p. 459), which are not equivalent to cash. Thus, using the information from PGA filings in an analysis of cash flows is without merit.

iii. The Companies double-count amounts used in the calculation

If the Commission finds the Companies' arguments for a separate PGA revenue lag convincing, the Commission should recognize that the calculation by the Companies double-counts amounts included in the calculation. (ICC Staff Exhibit 10.0, p. 7.) As demonstrated during the cross-examination of Company witness Subbakrishna, the amounts included in any given month on Line 9 of Schedule II in the PGA monthly filing are also included incrementally in the following two months' totals on Line 9 of Schedule II. (Tr., pp. 380-382.) The calculations for "Weight on True-Ups" (AmerenCIPS Exhibit No. 17.2; AmerenUE Exhibit No. 17.2) indicate that two-thirds of the Companies' PGA revenue is not collected from ratepayers until two months after it is originally estimated. (ICC Staff Exhibit 10.0, p. 8.) Common sense dictates that the totals the Companies chose to use in their calculations for PGA revenue lag are inappropriate, especially for dollar-weighting purposes.

b. Disallowance of PGA fuel costs

No allowance for fuel expense should be included in the CWC requirement because the Companies' analyses of PGA fuel costs do not support the calculated lead times they present. (Id., p. 17.) Staff noted a number of concerns in its review of the Companies' analyses. (Id., pp. 14-15.) The Companies addressed only the Staff concern related to out-of-period expenses because it was the "most significant" of Staff's concerns. (AmerenCIPS/UE Exhibit No. 31.0, p. 10.) The following Staff concerns were considered to be insignificant in that they were not addressed by the Companies:

1. AmerenUE costs included in calculation for AmerenCIPS fuel lead;
2. Interchange Sales included in CIPS analysis;
3. Charges for gas service facilities at a power plant included in both CIPS and UE analyses;
4. Four out of 64 invoices (6%) included in sample not supported by invoices provided to Staff; and
5. The invoices included in the analyses represent more than the total jurisdictional test year costs.

When asked during cross-examination how these concerns raised by Staff were addressed, Company witness Subbakrishna avoided answering the question by explaining that his ”objective was to determine what the spread in time was between the company getting an invoice and the company paying for that invoice”. (Tr., pp. 365-366.) This is contrary to Mr. Subbakrishna’s own definition of an expense lead, which is “the elapsed time from when a good or service is provided to the Company to the point in time when the Company pays for the good or service...” (AmerenCIPS Exhibit No. 6.0, p. 4.)

Based on Mr. Subbakrishna’s cross-examination, the Companies’ analyses were not based on a review of the invoices. When asked if he had examined all the invoices in the study to determine the extent to which Ms. Ebrey’s concerns other than the inclusion of out-of-period invoices were present in the data included in the lead/lag study, Mr. Subbakrishna gave an unfounded rationale for why he did not think it was necessary to consider those other concerns. (Tr., pp. 369-371.) In fact, he stated during cross-examination that he included or excluded invoices from his lead/lag study based on what the Companies’ accounts payable systems told him, not on an actual review of the invoices. (Tr., p. 370.) This is contrary to his written testimony wherein he states that he examined "invoices from transactions in which the Company bought natural gas". (AmerenCIPS Exhibit No. 6.0, p. 11.)

During cross-examination, Mr. Subbakrishna could not support his position that the invoices underlying the lead/lag study could be unrelated to the Companies' gas operations. When asked if Staff's concerns regarding PGA fuel costs could exist throughout the data used in his analyses, Mr. Subbakrishna again responded that it did not matter whether or not costs unrelated to either the specific Company or the specific type of expense being analyzed were included in his calculations. His rationale in not addressing Ms. Ebrey's other concerns was that any vendor might provide multiple products and services "and so on and so forth". (Tr., p. 371.)

Mr. Subbakrishna, when asked about including items that were not related to CIPS' gas operations, stated that he had only used actual test year costs for each Company in the calculation of each Company's CWC requirement. (Tr., pp. 396-397.) However, in calculating the expense leads, and thus the CWC factor, that was applied to the actual test year costs (AmerenCIPS Exhibit No. 31.3 and AmerenUE Exhibit No. 31.1, Cols. D and F respectively), he did include invoices for items which were not part of AmerenCIPS' PGA fuel costs. (Tr., pp. 352-371.) Therefore, in calculating the CWC requirements for CIPS and UE, he did include items unrelated to that specific utility's PGA fuel costs. Mr. Subbakrishna discusses industry standards with regard to fuel expense (Id., pp. 397-398), but that would not justify using invoices for electric operations or for affiliates in dollar-weighting the expense lead-time as he insinuates

(Id., p. 397). If that were the case, there would be no reason to calculate different expense leads for the various expense items included in the lead/lag study.

Mr. Subbakrishna's apparent unfamiliarity with the actual invoices provided in support of his analyses leads one to question whether he had, in fact, previously reviewed the actual documents which supported his analyses or if his analyses were based on "accounts payable" reports provided by the Companies without any direct knowledge of the detail behind those numbers. Without any assurance that the data actually represents what is purported, the results of the analyses cannot be given any weight in the ultimate decision based on that data. No allowance for PGA fuel expense should be included in the CWC requirements approved in this proceeding.

c. Disallowance of fuel expense and other operations and maintenance expense

Based on the Companies' lack of consideration to the receipt of goods or services for both fuel expense and other operations and maintenance expense, the Companies' calculations of lead-time for these areas should be disregarded. The Companies define an expense lead as "the elapsed time from when a good or service is provided to the Company to the point in time when the Company pays for the good or service". (AmerenCIPS Exhibit No. 6.0, p. 4.) However, when asked how the Companies considered delivery dates in their calculations for these two expense areas, the response was that no such consideration was given. (ICC Staff Exhibit 3.0, p. 9.) In an attempt to consider the obligation dates in the analyses, the Companies arbitrarily added 15.21 days invoice processing lead-time for fuel expense and other operations and maintenance expense. However, the Companies offered no support for this amount other than a calculation of "365/12/2". (AmerenCIPS/UE Exhibit No. 17.0, p.

14.) Staff surmises that this calculation could be based on the Companies' response to Staff data request CIPS-TEE-040 which indicates that only 12 invoices are received from any individual vendor in a year. (ICC Staff Cross Exhibit 5.0.) However, that response was invalidated during cross-examination when Ameren witness Subbakrishna admitted that there were up to 36 invoices received in a single year from an individual vendor, not 12 as the data response would indicate. (Tr., p. 389.) The calculated 15.21-day invoice processing lead-time is not supported by the information provided by the Companies.

During cross-examination, Mr. Subbakrishna insinuated that Staff's position from direct to rebuttal testimony had changed and it was appropriate to revert to the Companies' direct testimony position with regard to the treatment of the obligation date. (Tr., p. 384.) Staff's direct (ICC Staff Exhibit 3.0, p. 9) and rebuttal (ICC Staff Exhibit 10.0, p. 13) testimony positions are identical. Likewise, the Companies' position with regard to obligation date has been identical throughout this case — no consideration is given to the actual delivery dates of the goods or services related to fuel expense and other operations and maintenance expense. Without consideration to delivery dates, no accurate expense lead-time can be calculated and the Companies' analyses for fuel expense and other operations and maintenance expense should not be considered in the calculation of CWC.

d. Mid-point theory

During cross-examination, Staff witness Ebrey indicated that she was unsure about the resolution provided by the Companies in surrebuttal testimony regarding the proper use of the mid-point theory. At each stage of testimony, the Companies have provided Staff with new work papers supporting the revised lead/lag studies and CWC requirements. (Tr., pp. 345-347.) Staff did not receive the latest work papers supporting the Companies' surrebuttal testimony until June 27, 2003 — five business days before the hearings started — which severely limited the time available to review the latest studies. Since the PGA fuel expense and related PGA revenue represented 83% (6648/8005) of CIPS' CWC requirement and 73% (628/855) of UE's CWC requirement, those were the areas of Staff's focus. While the Companies did make some changes in response to Staff's concerns in this area, Staff was unable to determine if the changes made by the Companies adequately addressed those concerns.

e. Service Company involvement

During cross-examination, Staff witness Ebrey reiterated her concern regarding Service Company involvement with payments of expenses for both CIPS and UE. (Id., pp. 467-469.)

During cross-examination, Mr. Subbakrishna stated that at least for fuel costs, the utility business was moving towards a standard. (Tr., p. 397.) It follows that if the utility industry is moving towards a standard, the Service Company would also make payments based on certain standards, and lead/lag studies for the Companies would have negligible differences, making separate lead/lag studies unnecessary.

f. Conclusion

The Companies proposed cash working capital amounts of $8,005,000 for CIPS (AmerenCIPS Exhibit No. 31.1) and $855,000 for UE (AmerenUE Exhibit No. 31.1). Staff's position is that zero cash working capital be approved for both Companies since the proposed amounts are not adequately supported by the lead/lag studies performed. (ICC Staff Exhibit 10.0, p. 3.) The Companies respond that some level of cash working capital, other than zero, is appropriate. (AmerenCIPS/UE Exhibit No. 31.0, p. 3.) However, Company witness Subbakrishna agreed that CWC could be calculated to be zero or even a negative amount. Positive CWC would indicate that the shareholders were supplying CWC; negative CWC would indicate that the ratepayers were supplying CWC (Tr., pp. 334-336); and zero CWC would indicate that cash inflows and outflows on a day-to-day basis were optimized where no party had to supply CWC. (Tr., p. 475.) An efficient cash manager would strive towards this optimization of cash flows.

Staff witness Ebrey explained that since the Companies had not supported the level of CWC they had requested, a zero level would neutralize the impact of CWC on rate base. While Staff and the Companies may have reached a resolution of some of the concerns noted with the lead/lag study, basing the CWC requirement on just those agreed-upon components without considering other unresolved components of CWC would be tantamount to single-issue ratemaking. (Tr., pp. 471-473.)

Should the Commission decide to allow the Companies some positive CWC requirements in these rate cases, those amounts should be limited by the exclusion of the Fuel expense, which includes the impact of the separate PGA revenue lag, and the Other Operations and Maintenance expense components, resulting in a CWC requirement for CIPS of $881,000 and a CWC requirement for UE of $210,000, as calculated using the data included on AmerenCIPS Exhibit No. 31.1 and AmerenUE Exhibit No. 31.1. Staff would not be in agreement with such piece-meal treatment of the

CWC requirements and would suspect additional deficiencies in the areas not excluded since time limitations kept those areas from being fully reviewed.

3. Materials and Supplies

Staff witness Ebrey proposed adjustments to reduce the Companies' test year materials and supplies inventory balance for the amount of average materials and supplies included in accounts payable. The Companies revised the Materials and Supplies amounts to be included in rate base in the Schedules on AmerenCIPS Exhibit No. 14.2, and AmerenUE Exhibit No. 14.2 to reflect Staff's adjustments.

However, the Companies recommend that Staff's adjustment to Materials and Supplies be accepted only if the Commission also approves the Companies' full cash working capital requirements in rate base. (AmerenCIPS/UE Exhibit No. 31.0, p. 13.) The Companies are confusing two distinct elements of working capital. Cash working capital is an expense-based component of rate base, while Materials and Supplies Inventories are an asset-based component of rate base. (ICC Staff Exhibit 10.0, pp. 17-18.) The Commission found that these two items are separate and distinct components of rate base in the Illinois Power Company Delivery Services Tariffs Docket Nos. 99-0120/99-0134 (Consolidated), Order, pp. 23-24 (August 25, 1999).

Company witness Subbakrishna agreed, under cross-examination by Staff, that Materials and Supplies is a component of rate base, which represents shareholder investment. (Tr., p. 390.) The accounts payable associated with Materials and Supplies represents "vendor financing" of purchased merchandise until the bill for the merchandise has been paid in full. (ICC Staff Exhibit 3.0, p. 11.) Therefore, Staff's adjustment reducing Materials and Supplies to that amount representing only shareholder investment should be approved by the Commission independent of the decision regarding Staff's adjustment to cash working capital.

4. Working Gas in Storage

Staff recommends CIPS reduce its working capital allowance for gas in storage by $842,000. (ICC Staff Exhibit 17.0 Revised, Schedule 17.1 CIPS.) Staff's recommendation reduces the volume of gas assigned to five of CIPS' storage fields during the test year. CIPS disagrees with Staff's recommendation.

Staff's basis for recommending a reduction in CIPS' requested working capital allowance for gas in storage is simple and straightforward. Staff reviewed the volume of natural gas that CIPS requested for a working capital allowance in the test year and compared it to the volumes of natural gas in storage in historical periods. (ICC Staff Exhibit 4.0, p. 12.) This review indicated that the test year volumes were larger than any of the prior reviewed periods. (Id.) Therefore, Staff did not consider the volume of natural gas, and the associated value of that gas, to be a representative volume for gas in storage in the future.

CIPS agrees with Staff that the test year gas volumes were heightened. In particular, CIPS notes that the increased inventory at the Sciota storage field was attributable to reduced withdrawals as a result of unusually warm weather in 2001. (AmerenCIPS/UE Exhibit No. 11R, p. 11.) Not only does this support Staff's arguments, but this warm weather would have also impacted every other leased and company-owned storage field in 2001. (ICC Staff Exhibit 17.0 Revised, p. 17.) Therefore, CIPS itself provides the reason why its test year levels were higher than other historical levels -- the warm weather in 2001.

Aside from CIPS' agreement that test year levels were heightened, Staff also provides a schedule that compared the volume of natural gas contained in various storage fields versus the amount withdrawn from those fields over several winters for the five storage fields where CIPS and Staff are still in disagreement. (ICC Staff Exhibit 17.0 Revised, Schedule 17.5 CIPS.) This schedule shows that for four of the five fields, the percentage of natural gas removed during the winter season was the lowest during the test year. (ICC Staff Exhibit 17.0 Revised, p. 18.) This further indicated to Staff that the volume of natural gas contained in storage during the test year was higher than normal and should be adjusted downward. (Id.)

CIPS disagrees with Staff and, instead, claims that Staff should employ the same methodology that it did with CIPS' Panhandle and Trunkline leased storage agreements. (AmerenCIPS/UE Exhibit No. 24.0, pp. 10-16.) Perhaps not unsurprisingly, if Staff followed CIPS' logic it would no longer make any recommendation to reduce CIPS gas in storage value. Further, CIPS asserts that Staff acknowledged by recommending no volume adjustment for the Panhandle and Trunkline leased storage agreements that increasing the inventory of a storage field in a given year will cause historical average inventories to be unrepresentative of future years. (Id., p. 12.) Staff disagrees with the Company's assertion.

Regarding the Panhandle and Trunkline leased storage agreements, Staff notes that CIPS changed the contractual volumes associated with those agreements just prior to the start of the test year. (ICC Staff Exhibit 17.0 Revised, p. 17.) In particular, Staff notes that CIPS in the test year had significantly increased the amount of gas in those leased storage fields and that due to this change the only representative data for those fields was the test year information. (Tr., pp. 536-537.) In fact, the basis for Staff withdrawing its adjustments associated with those agreements was the large material change in the leased storage agreements, which caused Staff to consider the historical information for those agreements to no longer be representative of how CIPS would use those agreements in the future.

Further, CIPS' logic for making no volume adjustments at its other storage fields is fundamentally flawed. CIPS argues that since Staff accepted the test year volumes for the Panhandle and Trunkline leased storage agreements, then the historical gas volume information for its remaining storage fields is meaningless. This is the same as saying the historical costs incurred for every item for which CIPS has requested ratemaking treatment in this proceeding are useless and only the unique test year data should be considered to set rates. Staff has always reviewed historical information to verify the appropriateness of a utility's requested amounts. This is exactly what Staff is doing in making adjustments to CIPS' requested volume of natural gas for its working capital allowance for gas in storage. To do otherwise would be counter to appropriate ratemaking principles.

CIPS also attempts to dispute Staff's volume adjustment to gas in storage by alleging that the historical storage levels do not consider CIPS' increased reliance on storage as a hedging tool. (AmerenCIPS/UE Exhibit No. 24.0, p. 8.) However, CIPS fails to reconcile the fact that the physical price hedge created by natural gas storage -- the physical injection of natural gas in non-winter months and the withdrawal of natural gas in winter months – has always existed. CIPS' claim that its historical gas volumes at those fields are not representative of the future because the utility is not using its storage as a hedging tool is disingenuous. Staff noted the manner that CIPS operates its fields have not changed just because it is now claiming it is using storage for hedging. (Tr., p. 546.) Further, Staff noted that the volumes it used already took into account any changes CIPS made in the overall amount of natural gas it maintains in storage, especially the Panhandle and Trunkline leased storage agreements. (Id., p. 543.) Natural gas storage always has been and always will be a hedging tool. CIPS' claim that it is now using storage as a hedging tool does not indicate that the utility will inject or withdraw gas from its storage fields in a manner different than in the past. Therefore, the historical gas storage volumes are still representative of how CIPS will use storage in the future.

Aside from the general argument CIPS made for all storage fields, CIPS also had some specific discussion for each field that remains in disagreement. In particular, CIPS disagrees with Staff's recommended gas volumes for the NGPL and Texas Eastern leased storage fields. (AmerenCIPS/UE Exhibit No. 24.0, p. 7.) Specifically, CIPS argues that Staff fails to consider any increases to inventory at these fields. (Id.) However, CIPS fails to demonstrate that these agreements have changed and would require any adjustment. CIPS testifies that it had increased the capacity reserved for the Panhandle and Trunkline leased storage services, but makes no mention of increasing any contractual rights for the NPGL or Texas Eastern fields. (AmerenCIPS/UE Exhibit No. 11R, p. 13.) Further, a review of Staff's Schedule 17.5 CIPS indicates the capacity reserved for the leased storage fields from both of those pipelines (shown as NGPL DSS and TETCO SS1 on ICC Staff Exhibit 17.0 Revised, Schedule 17.5 CIPS) has not changed. This, in turn, means Staff's reliance on historical gas volumes for those agreements is valid. Therefore, Staff's recommendation to reduce the NGPL and Texas Eastern agreements by $26,000 and $135,000, respectively, is appropriate.

Regarding Staff's Ashmore storage field recommendation, CIPS disagrees with the volume Staff determined for this field. In particular, CIPS correctly notes it increased the gas inventory at the field by 185,000 MMBtu at the end of 2001. (AmerenCIPS/UE Exhibit No. 24.0, pp. 10-11.) However, it takes issue with Staff's manner of accounting for that 185,000. Instead of applying the methodology wherein Staff determines the appropriate percentage of the 185,000 MMBtu to add to CIPS historical volumes for the field, CIPS believes its full test year requested amount is appropriate. (Id., p. 11.) However, this argument ignores the fact that for the Ashmore storage field, Staff is able to provide an estimate of the percentage of that 185,000 amount that CIPS would retain in the field on a going forward basis. (ICC Staff Exhibit 17.0 Revised, p. 19.) Staff's methodology recognizes the fact that CIPS does not retain all of its gas in storage year round. (Id., Schedule 17.2, p. 2.) Instead, gas volumes in storage fluctuate due to the injection and withdrawal of gas over time. (Tr., pp. 538-539.) Therefore, Staff's recommended reduction to the gas storage value for the Ashmore storage field by $248,000, which includes an allowance for the additional 185,000 of gas, is superior to CIPS' "gives us everything we have asked for methodology".

Regarding the Sciota storage field, CIPS, as noted above, recommends Staff use the Panhandle/Trunkline methodology. However, CIPS fails to note that Staff increased its originally recommended volume for Sciota's allowed inventory by the full amount of the 50,000 MMBtu of additional inventory CIPS noted it had added to the field during the test year. (ICC Staff Exhibit 17.0 Revised, pp. 20-21.) Further, as Staff noted on cross-examination, the reason Sciota's additional test year inventory was treated differently than Ashmore's additional test year inventory is the manner in which CIPS uses those fields. In particular, a review of ICC Staff Exhibit 17.0 Revised, Schedule 17.5 CIPS indicates the Sciota storage field usage rate ranges from 21% to slightly over 25%. Whereas, this same document shows the Ashmore storage field usage rate ranged from 70% to 96%. The much lower usage rate for the Sciota storage field indicated to Staff that any additional volumes added to the Sciota field would not likely be cycled in and out of field. Therefore, the assumption to add all of the 50,000 MMBtu to the inventory was justified. (Tr., p. 541.) Staff's recommended gas volume for Sciota that recognized CIPS higher test year volume at the field while also including all of the 50,000 of additional inventory, is more appropriate than CIPS' requested amount.

Regarding the Johnston City storage field, CIPS states that the historical information Staff used to determine the appropriate volume of gas at the field is too small because it ignores the additional inventory that CIPS has added to the field. (AmerenCIPS/UE Exhibit No. 24.0, p. 15.) However, a review of the data that CIPS provided to Staff does not support this contention. In particular, ICC Staff Exhibit 17.0 Revised, Schedule 17.5 CIPS, shows the capacity amounts for the Johnston City storage field over a historical period. The capacity of the field for the 1998/1999 winter season exceeds all other periods with the exception of the 2002/2003 information. In short, the historical information has not supported CIPS' contention that it is incrementally adding gas to this field. Therefore, Staff's recommended volumes for the Johnston City storage field are valid.

The final storage field that Staff recommends a reduction in the volume in gas in storage is the Belle Gent storage field. Staff recommends CIPS retire the field. That retirement would result in the removal of all gas in storage associated with the field from CIPS' requested rates. (ICC Staff Exhibit 4.0, p. 19.) CIPS disagrees with Staff's recommendation. Staff's discussion regarding the merits of retiring the Belle Gent storage field is contained below in Section II.C.6. *infra*.

5. Accumulated Deferred Income Taxes

AG witness Effron proposed an adjustment to Accumulated Deferred Income Taxes ("ADIT") to not recognize ADIT for those items that are not recognized in the calculation of rate base. (AG Exhibit 1.0P CIPS, p. 9; AG Exhibit 1.0P UE, p. 9.) The Company countered that Mr. Effron's proposal results in an asymmetrical treatment of ADIT since it excludes certain deferred tax debit balances while not considering deferred tax credit balances. (AmerenCIPS/UE Exhibit No. 14.0, p. 7.) The Company also maintains that all deferred taxes should be treated consistently without selectively including or excluding any individual items. (AmerenCIPS/UE Exhibit No. 27.0, p. 4.) Staff did not offer testimony on this issue.

The Company's representation that Mr. Effron's proposal only excludes certain deferred tax debit balances is inaccurate because Mr. Effron's analysis (AG Exhibit 1.0P CIPS, Schedule B-2; AG Exhibit 1.0P UE, Schedule B-3) clearly includes an adjustment related to a deferred tax credit balance. Mr. Effron considered two debit and one credit balance in formulating his adjustment to ADIT.

Mr. Effron's adjustment excludes the ADIT associated with items simply because those items are not included in rate base. To rebut AG witness Effron's position, the Companies quote language from the final Order in Illinois Power Company Docket No. 89-0276, supporting the theory that ADIT items arising from timing differences related to book treatment vs. tax treatment of the same expense should be reflected in the calculation of rate base. (AmerenCIPS/UE Exhibit No. 14.0, p. 8.)

6. Retirement of Belle Gent Storage Field

Staff recommends that CIPS retire its Belle Gent storage field because the field is no longer used and useful. (ICC Staff Exhibit 4.0, pp. 20-23.) CIPS disagrees with Staff's recommendation.

The Act specifies what utility costs are allowed in a utility's rates. In particular, Section 9-211 of the Act states as follows:

> The Commission, in any determination of rates or charges, shall include in a utility's rate base only the value of such investment which is both prudently incurred and used and useful in providing service to public utilities customers. (220 ILCS 5/9-211.)

As the Act indicates, a rate based asset, such as the Belle Gent storage field, must be used and useful in providing service to customers in order for its costs to be included in a utility's rates. Staff's review determined that the Belle Gent storage field is no longer used and useful as defined by Section 9-212 of the Act. Section 9-212 defines "used and useful" as follows:

> A generation or production facility is used and useful only if, and only to the extent that, it is necessary to meet customer demand or economically beneficial in meeting such demand. (220 ILCS 5/9-212.)

The used and useful determination from Section 9-212 is essentially a two part test that requires a utility facility to either be "needed" to provide utility service to customers or provide "economic benefits" when providing service to customers in order to be allowed in to a utility's rate base. Staff's review indicates the Belle Gent storage field fails both tests.

Regarding the need portion of the test, Staff testified that CIPS is unable to rely on the Belle Gent storage field to offset its peak day demand because the facility is not necessary to meet CIPS' customer demand. (ICC Staff Exhibit 4.0, p. 21.) Further, the infrequency of CIPS' non-peak day use of the field does not support the need for the facility during non-peak day periods. (Id.)

CIPS agrees that it is unable to rely on the Belle Gent storage field to meet peak day load. In particular, CIPS provided a response to a Staff data request that noted the Belle Gent storage field is not used to meet peak day load because of the physical reservoir pressure difference between Belle Gent and the Johnston City storage field limits the peak day deliverability of Belle Gent to zero until February. (ICC Staff Exhibit 4.0, p. 22.) CIPS also provided testimony that stated it no longer considered the Belle Gent storage field as a resource for reducing interstate pipeline capacity requirements. (AmerenCIPS/UE Exhibit No. 24.0, p. 17.)

Staff also notes that for the period November 1, 1993 through the date of Staff's direct testimony (April 2, 2003), CIPS had only withdrawn gas from the Belle Gent storage field on 12 days during that period, with half of those days occurring outside of the normal winter season withdrawals used by storage field operators. (ICC Staff Exhibit 4.0, p. 23.) Further, CIPS admitted on each of those 12 days that its gas supply portfolio would have provided reliable service to its customers in the event the Belle Gent storage field was not available on those days. (Id.) In short, even though the Belle Gent storage field operated on those 12 days, the field was not necessary to meet customer demand. Therefore, the Belle Gent storage field fails the "need" portion of the requirements to be considered used and useful pursuant to Sections 9-211 and 9-212 of the Act.

As discussed above, the second half of the used and useful test requires a utility facility to provide an economic benefit when meeting customer demand. Staff's testimony demonstrates that in reviewing the cost of Belle Gent versus benefits ratepayers have received from the field over the past several years, the storage field does not provide an economic benefit to customers.

In particular, Staff conducted an analysis that calculated the overall costs that ratepayers bear as a result of CIPS maintaining and operating the Belle Gent storage field. This analysis indicated that CIPS customers, using the amounts assigned to the Belle Gent storage field in this proceeding, would see an annual revenue requirement of over $67,000 from allowing CIPS to continue operating the field. (ICC Staff Exhibit 17.0 Revised, p. 26.) Staff also noted that over the past seven years, the only year the storage field operated in the winter season and provided any economic benefits to CIPS' rate payers was in 2003. (Id.) When Belle Gent operated in 2003, it produced a savings to ratepayers of $17,000. (Id.) Multiplying the annual revenue requirement that Staff calculated by seven years (67,000 * 7) results in a cost of $469,000. Obviously, that cost does not compare favorably to the $17,000 in savings the ratepayers realized over the same time frame. Based on this analysis, Staff concludes the operation of the

Belle Gent storage field does not provide an economic benefit to ratepayers. (Id.) Therefore, the Belle Gent storage field fails the "economically beneficial" portion of the used and useful test.

However, CIPS did not agree with Staff's economic benefit analysis. In particular, CIPS claimed that Staff failed to consider the economic value of Belle Gent as a potential resource in the future to reduce firm transportation costs in its analysis. (AmerenCIPS/UE Exhibit No. 24.0, p. 18.) CIPS also claimed that Staff failed to consider the economic value of having Belle Gent as a backup to the Johnston City storage field should withdrawals from that field ever become reduced or limited due to problems. (Id. p. 19.) However, what is most interesting about CIPS' comments is the complete lack of any quantification of these alleged benefits or any statements by CIPS that indicated these alleged benefits outweighed the costs Staff determined for the continued operation of the Belle Gent storage field. Without that information, CIPS is merely speculating as to theoretical future value associated with the facility.

The only numerical value CIPS provided was the cost of leased storage on Trunkline for a service whose capacity matched that of the Belle Gent storage field. (Id.) However, that value is irrelevant to this discussion because, as Staff discussed above, the Belle Gent storage field historically operates very infrequently and on those occasions it did operate, CIPS could have replaced it with other system supply. Given the manner that CIPS has operated the Belle Gent storage field, CIPS should not replace it with any gas supply service should the Commission direct CIPS to retire its Belle Gent storage field.

Regarding CIPS' claim that there is some value to having Belle Gent available to back up the Johnston City storage, Staff notes that no other storage field operator in Illinois has determined it needs a complete storage field to back up the operations of another storage field. (Tr., pp. 526-527.) Also, Staff notes that neither was it aware of any historical problems at Johnston City nor has it seen any information that would indicate how having the Belle Gent storage field would provide a benefit to ratepayers. (Id., p. 527.) Finally, Staff notes that the Belle Gent storage field has a capacity of 500 MMBtu per day, while the Johnston City storage field is much larger (in excess of a factor of 10), so any potential benefit the Belle Gent storage field could provide as a backup to the Johnston City storage field is also minimized by the size differential between the two facilities. (Tr., p. 528.) In short, without any indication of reliability problems at the Johnston City storage field, Staff sees no value from using the Belle Gent storage field as a backup facility.

Finally, regarding CIPS' claim about some value for potentially upgrading the Belle Gent storage field in the future, Staff notes CIPS has just recently developed the Johnston City storage field and that it would likely make more sense to expand or upgrade that storage facility before making any investment at Belle Gent. (Tr., p. 530.) Also, Staff notes it had not seen any indication regarding future need for more storage in the area that is currently being served by the Belle Gent and Johnston City storage fields. (Id.) Finally, Staff notes that due to the pressure differential between the Belle Gent storage field and the Johnston City storage field, if CIPS conducted a complete upgrade at Belle Gent it would, at a minimum, require dehydration facilities and a compressor, which are fairly significant expenditures for a 500 per day field. (Id., pp.

530-531.) Given the small size of the Belle Gent storage field, Staff cannot foresee CIPS upgrading the facility, especially with the larger Johnston City storage field located nearby that would also be available for expansion or facilities upgrade in the future should CIPS desire to increase its storage capability.

CIPS has provided no information in this proceeding that indicates the Belle Gent storage field is needed to provide service to its customers or that the Belle Gent storage field provides any economic benefits to CIPS' customers when it does operate. Therefore, the facility is no longer used and useful in providing service to CIPS' ratepayers and the Commission should direct CIPS to retire the facility.

D. Recommended Rate Base

For the purpose of developing rates in this proceeding, Staff recommends that the Commission adopt a rate base of $166,409,000 for AmerenCIPS, as presented on Schedule 3 of Appendix A, and $15,908,000 for AmerenUE, as presented on Schedule 3 of Appendix B.

III. OPERATING REVENUES AND EXPENSES

A. Introduction

Schedules showing the operating revenues, expenses and income at present and recommended rates for the test year ending June 30, 2002, were presented by Company and Staff witnesses. Staff and several intervening parties proposed a number of adjustments to the Company's proposed operating statements, as discussed below.

B. Uncontested Issues

1. Charitable Contributions

Staff witness Ebrey proposed an adjustment to remove items from AmerenCIPS' operating expenses because the contributions are promotional, political in nature, specific to the Electric Industry, specific to AmerenUE, or Chamber of Commerce related events. (ICC Staff Exhibit 3.0, pp. 14-18.) AmerenCIPS' adjusted amount for Charitable Contributions accepts Staff's adjustment. (AmerenCIPS/UE Exhibit No. 14.0, pp. 2-3; AmerenCIPS Exhibit No. 14.5.) Since AmerenCIPS' rebuttal position accepted Staff's level of Charitable Contributions, ICC Staff Exhibit 10.0, Schedule 10.5 CIPS, reflects no adjustment for Charitable Contributions expense.

2. Membership Dues

Staff witness Ebrey proposed an adjustment to remove certain community organization dues from AmerenCIPS' recoverable miscellaneous general expenses not necessary in providing utility service. (ICC Staff Exhibit 3.0, p. 18.) Ameren's adjusted amount for Membership Dues Expense accepts Staff's adjustment. (AmerenCIPS/UE Exhibit No. 14.0, pp. 2-3; AmerenCIPS Exhibit No. 14.5.) Since AmerenCIPS accepted Staff's level of Membership Dues in its rebuttal position, ICC Staff Exhibit 10.0, Schedule 10.6 CIPS, reflects no adjustment for Membership Dues.

3. Customer Deposits and Interest Expense

Staff witness Ebrey proposed adjustments to reflect in AmerenCIPS and AmerenUE's test year rate base the 13-month average balance of customer deposits. (ICC Staff Exhibit 3.0, p. 19.) Ameren's adjusted amounts for Customer Deposits and Interest Expense accept Staff's adjustments. (AmerenCIPS/UE Exhibit No. 14.0, pp .2-

3; AmerenCIPS Exhibit No. 14.6; AmerenUE Exhibit No. 14.6.) Since the Company accepted Staff's levels of Customer Deposits and Interest Expense in its rebuttal position, ICC Staff Exhibit 10.0, Schedules 10.7 CIPS and 10.7 UE, reflects no adjustments for Customer Deposits and Interest Expense.

4. Outside Services Expense

In direct testimony, Staff witness Jones and AG witness Effron proposed similar adjustments to Outside Services Expense to correct errors made by the Companies in calculating the amount of test year expense. (ICC Staff Exhibit 1.0, p. 7.) Subsequently, the Companies provided additional information that supported the amount of Outside Services Expense as originally filed. Based upon a review of the information, Staff witness Jones withdrew her adjustments. (ICC Staff Exhibit 18.0, pp. 6-7.) AG witness Effron withdrew his adjustments at the July 9, 2003 Hearing. (Tr., pp. 411-412.) Since Staff accepted the Companies' level of Outside Services Expense, ICC Staff Exhibit 18.0, Schedules 18.7 CIPS and 18.7 UE reflect no adjustment for Outside Services Expense.

Outside Services Expense as originally filed by the Companies is reflected in the revenue requirements filed with Staff's rebuttal testimony, ICC Staff Exhibit 18.0, Schedules 18.1 CIPS and 18.1 UE. Therefore, no further action is required by the Commission.

5. Pension Expense

Staff witness Jones proposed to disallow expense related to a supplemental retirement plan and to survivor's benefits under the deferred compensation plan, both of which the Companies maintain for a few highly paid individuals. The plans provide benefits in addition to benefits provided under the Retirement Plan that covers all Company employees. (ICC Staff Exhibit 1.0, pp. 12-13.) The Companies accepted Staff's adjustments as evidenced by AmerenCIPS Exhibit No. 14.5 and AmerenUE Exhibit No. 14.5.

Staff's adjustments to Pension Expense, which are separate from and in addition to the Pension and Benefits Expense adjustment proposed by AG witness Effron, were adopted by AmerenCIPS and AmerenUE in their rebuttal positions and are uncontested.

6. Automated Meter Reading

Staff has withdrawn its recommendation that UE remove automated meter reading ("AMR") expenses from the proceeding. Originally, Staff recommended in sworn testimony that UE remove any expenses associated with its AMR project from the proceeding. (ICC Staff Exhibit 17.0 Revised, p. 10.) Staff's recommendation was based upon the lack of information in the Company's rebuttal testimony to support the AMR amounts requested in this proceeding. UE subsequently provided Staff with additional information through data request responses and through its surrebuttal testimony. During cross-examination, Staff noted that the additional information satisfied Staff's concerns and that Staff was withdrawing its recommendation to remove all of the expenses associated with UE's AMR project from this proceeding. (Tr., pp. 519-520.)

C. Contested Issues

1. Uncollectibles Expense

Staff witness Ebrey proposed adjustments to uncollectibles expense applying the five-year average rate to the Companies' requested revenue. (ICC Staff Exhibit 10.0, p.18.) The Companies faults this methodology stating that it does not consider increasing gas prices and that common sense would dictate that as gas prices increase, uncollectibles expense would likewise increase. (AmerenCIPS/UE Exhibit No. 27.0, p. 5.) However, under cross-examination, witness Opich agreed that based on the Companies' experience over the last five years, that relationship did not exist and increased revenues do not necessarily result in increased uncollectibles. (Tr., p. 296-297.)

The Companies attempted to illustrate that using an arithmetic average for calculating uncollectibles expense percentages does not consider upward or downward trends in those percentages. (Tr., p. 462.) While this may be true, the Companies' own historical data over the last five years does not indicate that any upward or downward trends in the Companies' revenues or uncollectibles expenses exist. (ICC Staff Exhibit 10.0, Schedules 10.3 CIPS and 10.3 UE.)

Staff disputes the Companies' attempt to establish a potential link between future gas costs and uncollectibles expense. In particular, the Companies testified that future NYMEX prices are in line with the NYMEX prices in place during the test year, therefore, the requested test year amounts are appropriate. (AmerenCIPS/UE Exhibit No. 11R, p. 19.)

Staff disagrees for three reasons. First, the Companies attempt to use gas forecasts to dispute Staff's recommendation, which relies on historical information. Second, the Companies assume a direct correlation exists between the alleged future high gas costs and high uncollectibles expense that has not been proven. Finally, the

Companies admit the NYMEX gas prices are not entirely reflective of the gas costs charged by the Companies.

The Companies filed a historical test year. The Commission's standard filing requirements, 83 Ill. Adm. Code 285.150(e), allow for pro forma adjustments for known and measurable changes in the operating results of a historic test year or if the changes are readily determinable. (ICC Staff Exhibit 17.0 Revised, p. 11.) Staff's adjustments to the uncollectibles expense rely on historical information and are allowed by the Commission's rules. However, the Companies attempt to rely upon forecasted gas costs to dispute Staff's adjustments. Since future gas costs are obviously neither known or measurable nor readily determinable, Staff does not believe forecasted gas costs are appropriate to support or dispute any values in this proceeding.

Regarding the Companies' assumption of a correlation between high gas costs and high uncollectibles expense, notwithstanding the problems noted above regarding the validity of future gas costs projections, Staff disagrees. In particular, Staff notes that a large amount of a gas utility's load results from winter heating. (Id., pp. 12-13.) If the utility experiences a warmer than normal winter, its customer's gas usage is reduced. Under that situation, if gas costs were still considered high, the bill impact would be reduced due to the lower usage. (Id., p. 13.) Therefore, if anything, the uncollectibles expense has some correlation to the temperatures experienced during the winter season, not the gas costs. (Id.)

Finally, the Companies admit the NYMEX gas prices are not entirely reflective of the gas costs charged by them due to the increased use of storage gas and other pricing mechanisms. (Id., p. 12.) In particular, during the test year the Companies increased the amount of natural gas they maintain in storage and they have also started using various financial instruments to hedge their gas supply. (Id.) The Companies' increased reliance on storage and financial instruments further demonstrates that a gas price forecast will likely not directly correspond to the price that ratepayers see from the Companies.

Therefore, the Companies' attempt to rely on gas price forecasts to dispute Staff's recommendation is unreasonable. Staff's methodology in determining the appropriate amount of uncollectibles expense in this proceeding is appropriate and more representative than the value requested by the Companies.

2. VRP Cost Recovery

Staff witness Jones proposed adjustments to disallow the amortized costs of the Voluntary Retirement Program ("VRP") because adding the VRP costs to test year expenses as proposed by the Companies would allow the Companies to recover the expense twice. (ICC Staff Exhibit 18.0, pp. 18-19.)

Approximately ninety-eight percent (98%) of the VRP expenses are for pension plan and other post employment benefits ("OPEB") costs. These costs represent the difference between the benefits earned to date by the voluntary retirees and the benefits to be received by them in the future. The Companies' pro forma test year pension and OPEB expenses are derived from the 2002 actuarial study, which does not reflect the retirements under the VRP. Therefore, annual pension and OPEB expenses for the retirees are included in the revenue requirement, and the Company will recover the expense in base rates until the next rate proceeding. If the Company were allowed to add the VRP costs as proposed, it would recover the expense twice. (Id.)

According to Company witness C. Kenneth Vogl, there is no “double recognition”. (AmerenCIPS/UE Exhibit No. 30.0, p. 4.) If rates based upon pension and OPEB expenses as filed were to be in effect for only one year, Ms. Jones would agree with Mr. Vogl. However, rates set in this case will be in effect for an indeterminate period of time.

Because Financial Accounting Standards (“FAS”) 87 pension expense and FAS 106 OPEB expense represent accruals to reflect the value of benefits earned during the year (AmerenCIPS/UE Exhibit No. 30.0, p. 3), base rates that reflect pension and OPEB expense as filed will allow the Companies to recover these expenses as if the voluntary retirees were still employed and retirement benefits for them were continuing to accrue on an annual basis. This continuing recovery of pension and OPEB expense for employees who have actually retired supplants the need for the Companies to also recover the VRP costs, which represent the value of the difference between the benefits earned to date of retirement and the benefits to be received by the voluntary retirees.

Because adding VRP costs to test year expenses as proposed by the Companies would allow them to recover pension and OPEB expense twice for VRP retirees, Staff witness Jones recommends that the Commission adopt her adjustment to disallow the amortized VRP costs included in the Companies’ revenue requirements. However, should the Commission decide that it is appropriate to allow the Companies to include the VRP costs in the revenue requirement, the ten-year amortization period proposed by AG witness Effron (AG Exhibit 1.0P CIPS, p. 20; AG Exhibit 1.0P UE, p. 18) is more reasonable than the three-year period proposed by the Companies (AmerenCIPS/UE Exhibit No. 14.0, p. 13), because the labor savings to the Companies derived from the early retirements will extend indefinitely into the future. At a three-year amortization level as proposed by the Companies, VRP costs would exceed VRP savings and ratepayers would receive no benefit from the VRP, from which the Companies expect to realize significant long-term savings.

3. Amortization of VRP Costs

The Companies propose to amortize the additional expenses incurred to implement the VRP over a three-year period on the basis that a three-year amortization period provides a more accurate matching of the additional costs and labor savings associated with the VRP. (AmerenCIPS/UE Exhibit No. 14.0, p. 13.) AG witness Effron believes an amortization period of ten years is reasonable and provides a better matching of costs and benefits than would a shorter period. (AG Exhibit 1.0P CIPS, p. 20; AG Exhibit 1.0P UE, p. 18.)

Staff witness Jones did not propose an amortization period because she believes the Companies should not be allowed to include the costs to implement the VRP in test year expenses for the reasons discussed in the section on VRP cost recovery. However, should the Commission decide that it is appropriate to allow the Companies to include the VRP costs in the revenue requirement, the ten-year amortization period proposed by AG witness Effron is more reasonable than the three-year period proposed by the Companies because the benefits to the Companies derived from the early retirements, i.e., labor savings, will extend indefinitely into the future. At a three-year amortization level as proposed by the Companies, VRP costs would exceed VRP savings and ratepayers would receive no benefit from the VRP, from which the Companies expect to realize significant long-term savings.

4. Backfill of VRP Positions

Staff witness Jones proposed adjustments to disallow the labor expense for positions left vacant by the VRP that the Companies intend to "backfill" because it does not meet the known and measurable standard required by 83 Ill. Adm. Code 285.150 for a pro forma adjustment. (ICC Staff Exhibit 18.0, p. 17.)

In rebuttal testimony, Company witness Thomas Opich presented pro forma adjustments to increase labor expense for 76 positions vacated by the VRP, some of which have been refilled and some of which the Companies expect to refill. (AmerenCIPS/UE Exhibit No.14.0, pp. 11-12.) Because the Companies were unable to provide information as to how many positions had actually been refilled, Staff witness Jones proposed adjustments to disallow the labor expense because it does not meet the known and measurable standard required by 83 Ill. Adm. Code 285.150 for a pro forma adjustment. (ICC Staff Exhibit 18.0, p. 17; Schedules 18.12 CIPS and 18.12 UE.)

In surrebuttal testimony, Company witness Opich testified that as of June 20, 2003, 60 employees have been hired and have begun work in "backfill" positions. Requisitions have been approved for the additional 16 positions. (AmerenCIPS/UE Exhibit No. 27.0, p. 7.) The Companies have included allocated labor expense for 76 backfill positions in their revenue requirements. (AmerenCIPS Exhibit No. 27.4 and AmerenUE Exhibit No. 27.4.)

Company witness Mark Lindgren asserts that the 60 positions already filled and the 16 positions with requisitions meet the known and measurable standard. (AmerenCIPS/UE Exhibit No. 28.0, p. 5.) However, upon cross-examination, Mr.

Lindgren stated that it is unknown on what date people will be hired or on what date the Company will begin to incur labor expense for the 16 positions. (Tr., p. 39.)

On cross-examination, Staff witness Jones agreed to allow the Companies' labor expense for the 60 positions that have been backfilled but not for the 16 positions that are unfilled. (Tr., p. 431.) Contrary to Company witness Lindgren's assertion, labor expense for the unfilled positions is not known and measurable. Appendix A, Schedule 6 and Appendix B, Schedule 6 reflect Staff's final adjustments to labor expense for the VRP backfill positions.

Staff witness Jones' adjustments to labor expense for 16 unfilled VRP backfill positions that are not known and measurable are appropriate and should be adopted by the Commission.

5. Pension and Benefits Expense

Under the guise of rebutting Staff witness Jones' testimony regarding the costs of the VRP, in the surrebuttal testimony of witness C. Kenneth Vogl, the Companies attempted to introduce new information regarding pension and OPEB expenses. (AmerenCIPS/UE Exhibit No. 30.0, pp. 4-7.) The AG filed a motion to strike Mr. Vogl's surrebuttal testimony and those portions of witness Opich's testimony based on Mr. Vogl's surrebuttal testimony. If the motion to strike is not granted, Staff recommends that the Commission reject the Companies' surrebuttal testimony adjustments to pension and OPEB expenses based on the updated 2003 budget numbers presented in the surrebuttal testimony of Mr. Vogl. The updated 2003 budget numbers are inappropriate surrebuttal testimony information and they are untimely and unverified.

In the surrebuttal testimonies of witnesses Vogl (AmerenCIPS/UE Exhibit No. 30.0, pp. 4-7) and Opich (AmerenCIPS/UE Exhibit No. 27.0, p. 6), the Companies seek to introduce new evidence in the form of updated 2003 budget amounts for pension and OPEB expenses. Supposedly, the updated budget amounts are to rebut Ms. Jones' contention that, if the Companies were allowed to add the one-time VRP costs as they propose to do, it would be a double counting of pension and OPEB expenses for the retirees. However, Mr. Vogl maintains there is no "double recognition" of the expenses. (AmerenCIPS/UE Exhibit No. 30.0, p. 4.) Therefore, the updated budget amounts were not offered to refute Ms. Jones' position regarding the VRP.

Neither were the updated budget amounts in response to adjustments made by Ms. Jones to disallow expenses related to a supplemental retirement plan and to survivor's benefits under the deferred compensation plan. The Companies accepted those adjustments (see Uncontested Issues, Pension Expense), which were the only adjustments related to pension and benefit expenses proposed by Ms. Jones.

Mr. Vogl was asked by the Company to update the 2003 budget amounts for pension and OPEB expenses in March 2003. (Tr., pp. 95-96.) The reason for the update was to reflect significant events that occurred during 2002. (AmerenCIPS/UE Exhibit No. 30.0, pp. 4-7.). Curiously, Mr. Vogl's surrebuttal testimony did not identify the acquisition of CILCO as one of the significant events that he considered in updating the numbers. This fact became evident only when Staff received his work papers one-half working day before the evidentiary hearings began. (Tr., p. 436.) There was no time to request information to verify Mr. Vogl's contention on the stand that the acquisition of Central Illinois Light Company ("CILCO") had no impact on the bottom line allocations to AmerenCIPS, AmerenUE, and Ameren Services. (Tr., p. 101.) The fact that the updated numbers are lower than what the Companies originally requested does not give them instant credibility. Perhaps the numbers would be even lower if the impact of CILCO were removed from the calculations.

Staff recommends that the Commission reject the Companies' surrebuttal testimony adjustments to pension and OPEB expenses that are based on updated 2003 budget numbers, which are inappropriate, untimely, and unverified.

6. Pension and Benefits, Capitalization Ratios

In determining his adjustments to pension and OPEB expenses, AG witness Effron calculated a capitalization rate based on the percentage of capitalized labor to total test year labor costs, since the capitalization rates provided by the Company seemed unreasonably low. (AG Exhibit 1.1, p. 14.) The Company explained how the capitalization rates provided on work papers WPC-3.10t (CIPS) and WPC-3.10v (UE) were calculated, allowing for the adjustment of capitalization balances when forecasted amounts are updated. (AmerenCIPS/UE Exhibit No. 27.0, p. 8.) Staff did not offer testimony regarding this issue.

7. Wage Expense, 2003 Collective Bargaining Unit Increase

Staff witness Jones proposed adjustments to reduce the Companies' test year pro forma wage expense and the associated payroll tax expense for pay increases in 2003 that are not reasonably certain. (ICC Staff Exhibit 1.0, p. 10.) The Companies accepted Staff's adjustments for the April 2003 management labor increase but they are contesting Staff's adjustments for the July 2003 contract labor increase.

Staff disallowed the 2003 pay increase for management labor because the Companies implemented a wage freeze for all management employees in 2003. (Id., pp. 11-12.) The Companies should not be allowed to increase management labor expenses for 2003 wage increases that they do not expect to incur. AG witness Effron also disallowed the 2003 pay increase for management labor. (AG Exhibit 1.0P CIPS, pp. 17-18; AG Exhibit 1.0P UE, pp. 15-16.) The Companies accepted the adjustments for management labor in their rebuttal testimonies as evidenced by AmerenCIPS Exhibit No. 14.5 and AmerenUE Exhibit No. 14.5. Since the Companies accepted Staff's adjustments for management labor, ICC Staff Exhibit 18.0, Schedules 18.9 CIPS and 18.9 UE reflect adjustments only for the contested 2003 wage increases for contract labor.

Staff's adjustment to Wage Expense for the 2003 pro forma salary increase for management labor was adopted by each Company in its rebuttal position and is uncontested.

Staff disallowed the wage increase for contract labor because it does not meet the known and measurable standard required for pro forma adjustments by 83 Ill. Adm. Code 285.150. (ICC Staff Exhibit 1.0, pp. 10-11.) According to the testimony of Company witness Opich at the July 9, 2003 Hearing, contract negotiations are in progress and no offers have been given. (Tr., p. 308.) Therefore, it is unknown when a new contract will take effect, if it will contain a pay increase, the rate of any increase, and the date the increase becomes effective.

It is not reasonable for ratepayers to pay for a pro forma wage increase that clearly does not meet the standard for a known and measurable change as required by

83 Ill. Adm. Code 285.150. Staff's adjustment is proper and should be accepted by the Commission.

8. Incentive Compensation Plan Expense

Staff witness Jones proposes to disallow labor and the associated payroll tax expenses related to incentive compensation plans because the plans are dependent upon financial goals of the Companies that primarily benefit shareholders; ratepayers provide funding even if no costs are incurred by the Companies because plan goals are not met; the plans are discretionary and may be discontinued at any time; and prior Commission precedent supports the disallowance of incentive compensation. (ICC Staff Exhibit 1.0, p. 14.) AG witness Effron also proposes to eliminate incentive compensation from the Companies' cost of service because the primary determinant is earnings per share ("EPS"), a shareholder goal. (AG Exhibit 1.0P CIPS, pp. 18-19; AG Exhibit 1.0P UE, pp. 16-17.)

a. Financial goals

Per incentive compensation plan ("ICP") documents, Ameren must achieve certain levels of financial success, as measured by the EPS, to have money available to fund the ICP. (ICC Staff Exhibit 1.0, p. 15.) If the EPS is below the threshold level set by the Board, no funds are available and no incentive compensation is paid, regardless of how well the employees meet their individual goals. (ICC Staff Exhibit 18.0, p. 13.)

According to Company witness Mark Lindgren, "…the most significant influence on the payment of incentives is the employee's individual and functional performance…" (AmerenCIPS/UE Exhibit No. 15.0, p. 8.) Because no incentive compensation is paid unless a threshold level of EPS is achieved, it is Staff's opinion that the most significant influence on the payment of incentives is whether or not the Companies achieve a certain financial goal. Since financial goals primarily benefit shareholders, shareholders should bear the cost of paying incentive compensation. Per testimony provided by Mr. Lindgren at the evidentiary hearings, nothing prevents the Companies from offering the plans even if the cost of the plans is not recovered through rates. (Tr., p. 42.)

b. Ratepayer funding and discretionary nature of plans

If incentive compensation is allowed to be recovered through rates, ratepayers will pay the cost whether or not the Company incurs it. The Commission has been concerned about this issue in the past:

> The Commission is also concerned that if the ICP payments are not made, the Company still recovers the cost through rates. If the Company's financial goals are not met or if an individual's goals are not met, MEC may choose not to pay the incentive compensation portion of wages. Under MEC's proposal, however, it would still recover the cost through rates. (MidAmerican Energy Company, ICC Docket No. 01-0696, p. 17; Order entered Sept. 11, 2002.)

> [T]he Commission is concerned that ratepayers are not protected if IP fails to achieve the financial goals and incentive compensation payments are not made. Under that scenario, ratepayers would still pay for the incentive compensation plan if IP's position were adopted. (Illinois Power Company, ICC Docket Nos. 99-0120/99-0134 (Cons.), p. 44; Order entered Aug. 25, 1999.)

> Furthermore, the Commission is not persuaded that ratepayers are protected in the event that the targeted return on capital investment is not achieved. Under CILCO's proposal, ratepayers would still fund the test year level of incentive payments even if that level is not achieved. While failure to achieve the efficiencies that would result in the projected level of incentive payments may penalize individual managers, ratepayers receive no benefit from this "penalty." Shareholders, on the other hand, would benefit. (Central Illinois Light Company, ICC Docket Nos. 99-0119/99-0131 (Cons.), p. 38; Order entered Aug. 25, 1999.)

(ICC Staff Exhibit 1.0, pp. 16-17.)

Company witness David Cross testified that Staff's "position the utility could recover incentive compensation expense in rates but then not pay out the compensation, is not grounded in market reality." (AmerenCIPS/UE Exhibit No. 16.0, p. 11.) He also states "…I cannot foresee at this time, in this marketplace, where it would be prudent for Ameren to discontinue the incentive compensation plans." (Id., p. 10.)

The Companies have notified bargaining unit employees covered by the 2002 Ameren Incentive Plan ("AIP") that they are not planning to offer the AIP in 2003, thus proving that the Companies' incentive compensation plans are discretionary and may be suspended (or discontinued) at any time, even at the risk of being imprudent, as suggested by Mr. Cross. (ICC Staff Exhibit 18.0, p. 14.) If the Companies were allowed to include incentive compensation in their revenue requirements, ratepayers would provide funding (through rates) even if no cost were incurred by the Companies because plan goals were not met – or, in this instance, because the Companies decided to suspend the incentive plan. (Id., p. 15.)

Based upon the fact that the AIP has been suspended, in surrebuttal testimony the Companies removed the expense associated with this plan from their respective revenue requirements. (AmerenCIPS/UE Exhibit No. 27.0, pp. 8-9.) The incentive compensation associated with management employees of AmerenCIPS, AmerenUE, Ameren Services Company and Ameren Fuels and Services Company is still contested. (Id.)

c. Precedent for disallowing incentive compensation

Although every case stands on its own merits, the Commission has rejected the costs for incentive compensation in numerous cases. (ICC Staff Exhibit 1.0, p. 18.)

- MidAmerican Energy Company: Docket Nos. 01-0696, 01-0444 and 99-0534;
- Central Illinois Light Company: Docket Nos. 01-0465/01-0530/01-0637 (Cons.), 99-0119/99-0131 (Cons.), and 94-0040;
- Illinois Power Company: Docket Nos. 01-0432, 99-0120/99-0134 (Cons.), 93-0183, and 91-0147;
- AmerenCIPS and AmerenUE: Docket No. 00-0802;
- Consumers Illinois Water Company: Docket Nos. 95-0641, 95-0307/95-0342 (Cons.); and
- Citizens Utilities Company of Illinois: Docket No. 94-0481

Staff witness Jones' adjustments to disallow labor and the associated payroll tax expenses related to incentive compensation plans are just and reasonable and should be adopted by the Commission.

9. Advertising Expense

Staff witness Ebrey proposed adjustments to advertising expense which disallow both out-of-period costs and costs which do not reflect an ongoing level of expense. (ICC Staff Exhibit 10.0, Schedules 10.4 CIPS and 10.4 UE.) The Companies agreed that those costs described by Staff as out-of-period should not be included in advertising expense in this rate proceeding (AmerenCIPS/UE Exhibit No. 27.0, p. 11) and have adjusted operating expenses to reflect that portion of Staff's adjustment (AmerenCIPS Exhibit No. 27.4 and AmerenUE Exhibit No. 27.4).

The Companies agree that the other costs disallowed by Staff are not representative of an ongoing level of expense and suggest that the contested advertising costs could possibly be amortized as rate case expenses.

(AmerenCIPS/UE Exhibit No. 27.0, p. 11.) That being said, the Companies made no effort to reclassify those costs in the proposed revenue requirements and**,** in fact, have not indicated that the rate case expense requested in this case is less than adequate.

Since the Companies have agreed that the reasons behind both components of Staff's adjustments to Advertising Expense are correct, Staff's adjustments should be approved as set forth on ICC Staff Exhibit 10.0, Schedules 10.4 CIPS and 10.4 UE.

10. Meter Reading Expense, Non-Labor

AG witness Effron proposed an adjustment to normalize the non-labor expenses charged to Meter Reading Expense since costs associated with the transition period are abnormal or of a non-recurring nature. (AG Exhibit 1.0P UE, p. 23.) The Company pointed out that the costs associated with the reduction of labor expense are included as non-labor costs of the Automated Meter Reading ("AMR") System at a level which the Company expects to continue. (AmerenCIPS/UE Exhibit No. 14.0, p. 20.) Mr. Effron reiterated that the costs to effect the transition will no longer be necessary once the transition is complete, thus costs for meter reading should be normalized. (AG Exhibit 1.1, p. 15.) The Company stated that, while costs were incurred to deliver exceptional service and make the transition easier, it expects that level of expense to continue. (AmerenCIPS/UE Exhibit No. 27.0, p. 12.) Staff did not offer testimony on the issue.

11. Income Tax Expense

Staff witness Ebrey proposed adjustments to income tax expense for both CIPS and UE to correct the level of expense included in the Companies' Operating Income at Present Rates. (ICC Staff Exhibit 10.0, Schedules 10.8 CIPS and 10.8 UE.) While the

Companies are accepting Staff's methodology of calculating income tax expense (AmerenCIPS/UE Exhibit No. 27.0, p. 13), the Companies do not reflect Staff's proposed adjustment in their surrebuttal position. The Companies argue that the Staff adjustment to income tax expense does not impact the income taxes at proposed rates. (AmerenCIPS/UE Exhibit No. 14.0, p. 21.) However, the income tax expense at Staff's proposed rates is not independently calculated. The income tax expense at proposed rates in Staff's revenue requirement model is simply a sum of all prior columns. If the income tax expense at present rates is incorrect, as it is reflected in the Companies' filings in Staff's revenue requirement model, the income tax expense at proposed rates will not be correct.

Under cross-examination, Company witness Opich admitted that Staff's methodology accepted by the Company does not include Schedule M deductions. Mr. Opich further agreed that the only difference between the Companies' calculation of income tax expense at present rates and the adjusted income tax expense proposed by Staff is the exclusion of Schedule M items in Staff's calculation. (Tr., p. 302.)

The mechanics of Staff's revenue requirement model require that the income taxes at present rates be correctly calculated. In agreeing to Staff's methodology, which excludes Schedule M deductions, the Companies have, in effect, agreed to Staff's adjustment to income tax expense on operating net income at present rates. Therefore, the Commission should approve Staff's adjustment to income tax expense.

12. Allocation of Rate Case Expense

a. Allocation of unamortized rate case expenses

Staff witness Jones proposed adjustments to the Companies allocations of unamortized rate case expenses from the prior rate case. (ICC Staff Exhibit 1.0, p. 8.) In the prior rate cases, Docket No. 98-0545 for CIPS and Docket No. 98-0546 for UE, the rate case expenses were split between the companies based on their relative total revenues. In the current rate case, the expenses have been split equally, including the unamortized portion from the prior rate case. Staff's adjustment corrects unamortized prior rate case expense for each Company to reflect the allocation method and amount that was approved in the previous rate case. The Companies accepted Staff's adjustments as evidenced by AmerenCIPS Exhibit No. 14.5 and AmerenUE Exhibit No. 14.5. The unamortized prior rate case expenses were not included in the recoverable rate case costs allowed by AG witness Effron, as evidenced by AG Exhibit 1.0P CIPS, Schedule C-2 and AG Exhibit 1.0P UE, Schedule C-1.

b. Allocation of current rate case expenses

The Companies split the cost of the rate cases 50/50 between CIPS and UE. AG witness Effron proposed an adjustment to allocate rate case expense based on the relative size of the proposed rate bases of AmerenCIPS and AmerenUE. (AG Exhibit 1.0P CIPS, p. 25; AG Exhibit 1.0P UE, p. 26.) The Companies maintain that the expense incurred in filing rate proceedings does not differ appreciably based on the size of the operations of a company. (AmerenCIPS/UE Exhibit No. 14.0, p. 15.) Mr. Effron does not disagree with that position; he simply offers an alternative allocation method that he believes is more reasonable. (AG Exhibit 1.1, p. 10.)

Given the fact that the costs incurred to prepare and file simultaneous rate cases for the affiliated interests in this consolidated proceeding are not materially affected by the size of each company, the Companies' method to allocate the current rate case expenses equally appears to be a fair sharing of the costs.

13. Amortization of Rate Case Expense

Staff witness Jones proposed an adjustment to amortize rate case costs over five years instead of the three-year period proposed by the Companies. (ICC Staff Exhibit 1.0, p. 9.) AG witness Effron also proposed an adjustment to amortize rate case costs over a five-year period. (AG Exhibit 1.0P CIPS, pp. 25-26; AG Exhibit 1.0P UE, pp. 25-26.)

Per Company witness Opich "…the Companies expect to seek further rate relief in three years." (AmerenCIPS/UE Exhibit No. 14.0, p. 15.) However, the Companies' response to Staff data request CIPS&UE-BCJ-6.02 states "…it is not definite that the Companies will seek rate relief in three years." (ICC Staff Exhibit 18.0, p. 8.) Five years is the average time period between rate case filings since 1982 for CIPS. Five years is also the approximate length of time between when the Order was entered in the prior rate case for each Company and when the Order will be entered for the current proceedings.

Based on the Companies' history of rate case filings, five years is a reasonable expectation of time between rate cases. Therefore, the five-year amortization period for rate case expense proposed by Staff is appropriate and should be adopted by the Commission.

D. Recommended Operating Income/Revenue Requirement

For the purpose of developing rates in this proceeding, Staff recommends that the Commission adopt a revenue requirement of $60,687,000 for AmerenCIPS, as presented on Schedule 1 of Appendix A, and $7,257,000 for AmerenUE, as presented on Schedule 1 of Appendix B.

IV. COST OF CAPITAL/RATE OF RETURN

Three witnesses submitted testimony regarding AmerenCIPS' and AmerenUE's costs of capital. Witness McShane presented the Companies' analyses of their costs of equity as well as an analysis of AmerenUE's capital structure. (AmerenCIPS Exhibit Nos. 4.0-4.3; AmerenUE Exhibit Nos. 4.0-4.3; AmerenCIPS/UE Exhibit Nos. 13.0 and 26.0-26.1.) Witness O'Bryan presented the Companies' capital structures, costs of debt, costs of preferred stock, and weighted average costs of capital ("WACC"). (AmerenCIPS Exhibit Nos. 3.0-3.5; AmerenUE Exhibit Nos. 3.0-3.5; AmerenCIPS/UE Exhibit Nos. 12.0 and 25.0-25.1.) Staff witness McNally presented an analysis of AmerenCIPS' and AmerenUE's capital structures, costs of equity, costs of debt, costs of preferred stock, and WACC. (ICC Staff Exhibit 6.0; Revised ICC Staff Exhibit 13.0.)

A. Capital Structure

Company witness O'Bryan presented the Companies' proposed capital structures for the June 30, 2002 measurement date. AmerenCIPS' proposed capital structure consisted of $547,322,289 of long-term debt (46.927%), $78,387,002 of preferred stock (6.721%), and $540,611,588 of common equity (46.352%). (AmerenCIPS Exhibit 3.0, Schedule 3.5.) AmerenUE's proposed capital structure consisted of $1,637,741,353 of long-term debt (37.094%), $114,502,040 of preferred stock (2.594%), and $2,662,834,920 of common equity (60.312%). (AmerenUE Exhibit 3.0, Schedule 3.5.)

Staff's capital structure recommendation for AmerenCIPS contained $597,467,757 of long-term debt (49.12%), $78,387,002 of preferred stock (6.44%), and $540,611,588 of common equity (44.44%). (ICC Staff Exhibit 6.0, Schedule 6.1 CIPS.) Staff recommended adopting an imputed capital structure for AmerenUE consisting of 1.4% short-term debt, 43.6% long-term debt, 2.3% preferred stock, and 52.7% common equity. (Revised ICC Staff Exhibit 13.0, Schedule 13.1 UE.)

1. Uncontested Issues

a. AmerenCIPS' Capital Structure

Company witness O'Bryan's and Staff witness McNally's capital structure proposals for AmerenCIPS differ with respect to the amount of long-term debt to include. Among the adjustments Mr. McNally made to the long-term debt schedules presented in Mr. O'Bryan's direct testimony was the reinstatement of the $50 million 7.5% Series X, which Mr. O'Bryan had removed based on AmerenCIPS' plan to redeem that series. Mr. McNally explained that the Company had not satisfactorily demonstrated how it would finance that forecasted retirement. (ICC Staff Exhibit 6.0, pp. 5-6.) Mr. O'Bryan did not respond to the arguments Mr. McNally made regarding AmerenCIPS' capital structure. Further, the Company did not include AmerenCIPS' capital structure in its list of contested issues. (*See* Ameren Companies' Chart of Contested Issues.) Thus, the Commission should adopt Mr. McNally's proposed capital structure of $597,467,757 of long-term debt (49.12%), $78,387,002 of preferred stock (6.44%), and $540,611,588 of common equity (44.44%).

b. AmerenUE's Cost of Preferred Stock

Staff and the Company agree that AmerenUE's cost of preferred stock is 5.19%. (AmerenUE Exhibit No. 3.5; Revised ICC Staff Exhibit 13.0, Schedule 13.1 UE.)

2. AmerenUE, Common Equity Percentage

Mr. McNally argued that AmerenUE's June 30, 2002 capital structure was not appropriate for ratemaking purposes, since that capital structure, in isolation, reflects a credit rating in the AAA range, which is unnecessarily expensive. (Revised ICC Staff Exhibit 13.0, p. 11.) AmerenUE's June 30, 2002 total debt ratio of 37.89% is significantly below the low end of the Standard & Poor's ("S&P") benchmark range of 42.0% to 47.5% for an AA-rated utility with a business position of 3. Mr. McNally's recommended capital structure is based on a total debt ratio of 45%. To establish the individual capital component proportions, the 45% total debt capital was divided between short-term and long-term debt based on the proportion of the total debt capital each composed in AmerenUE's actual June 30, 2002 capital structure. Likewise, the 55% of non-debt capital was divided between common and preferred stock based on the proportion of non-debt capital each composed in AmerenUE's actual June 30, 2002 capital structure. Mr. McNally's approach establishes a capital structure consistent with that of an AA-rated utility with a business profile of 3, which is a reasonable debt rating for ratemaking purposes.

Ms. McShane argued that no adjustment is necessary. Ms. McShane maintained that AmerenUE's proposed equity ratio of 60.3% is reasonable because it lies within the range of the common equity ratios for the nine-company natural gas utility sample ("Gas Sample") from which Mr. McNally derived his cost of equity estimate. (AmerenCIPS/UE Exhibit No. 13.0, p. 3.) However, Ms. McShane's comparison is not meaningful since it focuses on the highest equity ratios. The Company's recommended equity ratio of 60.3% exceeds that of every company in the sample but one. However, the mere existence of companies with higher common equity ratios does not demonstrate that AmerenUE's equity ratio is suitable for ratemaking purposes. A logical approach to determining the reasonableness of a capital structure would be to compare it to the typical (i.e., average) equity ratio, rather than to most extreme observations, which are more likely to be unreasonable themselves.[1] Even when short-term debt and long-term debt due within one year are excluded from the ratio calculations, which inappropriately inflates the calculated equity ratio for the Gas Sample, the 60.3% equity ratio of AmerenUE's proposed capital structure still exceeds the 2002 mean equity ratio of the Gas Sample by 8%. Moreover, when short-term debt and debt due within one year are added in, the difference is even greater. Thus, Ms. McShane's comparison of AmerenUE's common equity ratio to the highest, incorrectly calculated equity ratios in the sample does not demonstrate that AmerenUE's proposed capital structure is reasonable for ratemaking purposes. (ICC Staff Exhibit 6.0, pp. 12-13.)

Ms. McShane also argued that the adjustment to the capital structure constitutes double counting when an adjustment to the cost of equity is also made. (AmerenCIPS/UE Exhibit No. 13.0, pp. 7-8.) Ms. McShane's argument is incorrect. Mr. McNally's recommended adjustments do not overlap. Mr. McNally's recommendations merely include two smaller adjustments, one to the capital structure and one to the cost of equity, as an alternative to a single larger adjustment to either. That is, if Mr.

[1] Significantly, Ms. McShane's and Mr. McNally's cost of equity recommendations focus on the central tendency of the sample cost of equity estimates rather than the highest or lowest sample cost of equity estimates.

McNally's capital structure adjustment were not made, a much larger cost of equity adjustment would be required. Conversely, if Mr. McNally's cost of equity adjustment were not made, a much larger capital structure adjustment would be required. The capital structure adjustment Mr. McNally recommended establishes a reasonable capital structure for an AA-rated utility with a business profile of 3. However, the Gas Sample, which has an average business profile of 3, has an average credit rating of only A. An A rating indicates a considerably higher level of financial risk than that Mr. McNally imputed for AmerenUE. Given that even after imputation, AmerenUE's risk remains lower than the Gas Sample's risk, financial theory maintains that investors would require a lower return than that indicated by the Gas Sample. Therefore, in addition to the capital structure adjustment, a 25 basis point reduction to the cost of equity of the Gas Sample is necessary to establish a reasonable cost of equity estimate for AmerenUE.[2] (ICC Staff Exhibit 6.0, p. 11.)

Ms. McShane objected to Mr. McNally's use of S&P debt ratio benchmarks, noting that it is not imperative for a utility's debt ratio to be within the benchmarks for a particular credit rating for the utility to receive that credit rating. (AmerenCIPS/UE Exhibit No. 13.0, pp. 4-7.) Ms. McShane is correct that S&P benchmarks are not absolute. However, a utility's capital structure ratios are but one factor used to determine a credit rating. While it is possible for a utility to receive a given credit rating despite having a debt ratio outside the benchmarks for that rating, such a deviation indicates that other factors, such as the utility's pre-tax interest coverage, offset the

[2] To eliminate the need for a direct adjustment to the Gas Sample's cost of equity, AmerenUE's imputed capital structure ratio would need to be consistent with an A credit rating.

difference between the financial risk implied by the utility's debt ratio and that implied by the benchmarks. Ms. McShane did not demonstrate that weakness in other utility factors requires AmerenUE to maintain a more conservative capital structure than that suggested by the benchmarks.[3] (ICC Staff Exhibit 6.0, p. 15.) On the contrary, Mr. McNally has demonstrated that the implied pre-tax interest coverage ratio based on his recommendations, including adjustments both to AmerenUE's capital structure and cost of equity, would be approximately 4.6x for AmerenUE. S&P's guidelines for pre-tax interest coverage ratios for companies with business profile scores of 3 range from 3.4 to 4.0 for an AA rating. Thus, Mr. McNally's recommendation is supportive of an AA level of financial strength. In contrast, a cost of capital incorporating Mr. McNally's capital cost recommendations and his calculation of AmerenUE's June 30, 2002 capital structure, before imputation, results in an implied pre-tax interest coverage ratio of approximately 5.8x, or almost 50% above the high-end of the AA benchmark range. Thus, the pre-tax interest coverage ratio associated with AmerenUE's June 30, 2002 capital structure is unreasonably high relative to the guidelines for a company with a level of business risk similar to AmerenUE's gas operations to maintain an AA rating, which indicates that AmerenUE's June 30, 2002 capital structure is not appropriate for ratemaking purposes. (ICC Staff Exhibit 6.0, pp. 11-12.)

Ms. McShane suggested that if AmerenUE's actual business profile score of 4 were used, only a minimal capital structure adjustment would be required.

[3] AmerenUE's affiliation with unregulated and non-utility companies is a source of weakness. (ICC Staff Exhibit 6.0, pp. 9-10.) Nevertheless, increases in a utility's risk and cost of capital directly or indirectly arising from that utility's affiliation with unregulated and non-utility companies cannot be reflected in rates pursuant to Section 9-230 of the Act. (220 ILCS 5/9-230.)

(AmerenCIPS/UE Exhibit No. 26.0, pp. 3-4.) Although S&P currently assigns AmerenUE a business profile score of 4, that business profile score reflects AmerenUE's higher risk electric generation operations. Mr. McNally concluded that if the effects of the higher risk electric generation operations were removed, AmerenUE would be assigned a business profile score of 3. Mr. McNally noted that AmerenCIPS' business profile score was changed to 3 from 4 shortly after AmerenCIPS transferred its electric generation assets to an affiliate. Mr. McNally further noted that most gas distribution utilities have a business profile score of 3. Thus, a business profile score of 3 is appropriate. (ICC Staff Exhibit 6.0, pp. 9-10.) Moreover, Ms. McShane agrees with the use of a business profile score of 3 and states:

> The parent company, Ameren Corporation, for which market data are available, is primarily an electric utility, and its market data reflect the risks associated with that business. Hence, rather than estimate a fair return for AmerenUE's Illinois gas operations by reference to market data for Ameren, the cost of attracting capital tests should be applied by reference to proxy companies that operate in the gas distribution business to ensure that the market data capture the business risks to which AmerenUE's Illinois gas operations are exposed.
>
> *****
>
> The average S&P business profile ranking of the LDCs in my sample is "3". By comparison, AmerenUE's overall operations are ranked "4". Although AmerenUE is riskier on this scale than the average LDC, there is no critical element of the business risk profile of AmerenUE's Illinois gas operations that would lead investors to perceive AmerenUE's Illinois gas operations as facing materially higher or lower business risks than the average LDC in my sample. (AmerenUE Exhibit No. 4.0, pp. 5-6.)

3. Short-Term Debt Balance

Mr. McNally used the following formula to calculate the short-term debt balance:

> The net balance of short-term debt is the greater of a) the monthly ending gross balance of short-term debt outstanding minus the corresponding monthly ending balance of construction-work-in-progress ("CWIP") accruing an allowance for funds used during construction ("AFUDC") or b) the monthly ending gross balance of short-term debt outstanding minus the corresponding monthly ending value of CWIP accruing AFUDC times the ratio of short-term debt to total CWIP. (Revised ICC Staff Exhibit 13.0, pp. 5-6.)

Mr. O'Bryan argued that Mr. McNally's short-term debt balance calculation formula falls short when analyzed from a sources and uses of cash flow point of view, since it assumes that if CWIP is not financed on a cash basis through short-term debt, then it must be financed through permanent capital. (AmerenCIPS/UE Exhibit No. 25.0, pp. 5-6.) Mr. O'Bryan contended that contrary to an underlying assumption in the AFUDC formula, internally generated cash is the first source of financing for CWIP, and that internally generated cash flow reflects other sources in addition to permanent capital. Mr. O'Bryan recommended that the traditional formula for calculating short-term debt (part "a" only) should be used until a more accurate formula can be devised. Mr. O'Bryan noted that in ICC Docket No. 00-0802 Mr. McNally used only part "a" of the formula presented above to calculate the net short-term debt balance of AmerenCIPS. (AmerenCIPS/UE Exhibit No. 12.0, pp. 6-7.)

Mr. O'Bryan's distinction between cash flow and capital is not appropriate. As Mr. O'Bryan acknowledged, cash is an asset, and all cash is pooled together into a single cash asset account. (Tr., pp. 594-595.) Thus, each dollar of cash is perfectly interchangeable with any other dollar of cash, making the tracing of capital from source to use impossible. Yet, Mr. O'Bryan's claim that internally generated cash is the first source of financing for CWIP explicitly traces capital from source to use. Nevertheless, despite the fungible nature of capital, the ICC formula for calculating the AFUDC rate artificially assumes that short-term debt is the first source of financing for CWIP, and reflects the cost of that short-term debt in AFUDC. Given that part of the cost of short-term debt is reflected in AFUDC, the remainder of the cost of short-term debt must be reflected in the rate of return on rate base. Mr. McNally's formula does just that. The new formula represents a refinement of the short-term debt calculation used in Docket No. 00-0802 that more accurately measures the cost of short-term debt for ratemaking purposes. The Commission has incorporated the formula Mr. McNally used into 83 Ill. Adm. Code 285.

4. Recommended Capital Structure

Staff recommends a capital structure for AmerenCIPS containing 49.12% long-term debt, 6.44% preferred stock, and 44.44% common equity. Staff recommends a capital structure for AmerenUE containing 1.4% short-term debt, 43.6% long-term debt, 2.3% preferred stock, and 52.7% common equity.

B. Cost of Debt

1. Cost of Long-Term Debt

Company witness O'Bryan proposed 6.672% and 5.941% costs of long-term debt for AmerenCIPS and AmerenUE, respectively. (AmerenCIPS Exhibit No. 3.5; AmerenUE Exhibit No. 3.5.) Staff witness McNally made several adjustments to the Companies' proposed costs of long-term debt. (ICC Staff Exhibit 6.0, pp. 5-6; Revised ICC Staff Exhibit 13.0, p. 5.) These adjustments resulted in proposed 6.74% and 5.94%

costs of long-term debt for AmerenCIPS and AmerenUE, respectively. (ICC Staff Exhibit 6.0, Schedule 6.1 CIPS; Revised ICC Staff Exhibit 13.0, Schedule 13.1 UE.) Of the adjustments Mr. McNally made to the Companies' long-term debt schedules, Mr. O'Bryan objected only to the adjustment to the interest rate applied to the variable rate Environmental Improvement ("EI") bonds.

Mr. O'Bryan maintained that the interest rate for the variable rate EI bonds should be the trailing twelve-month average interest rate as of June 30, 2002 that AmerenUE incurred for those bonds, rather than the rate AmerenUE incurred as of May 21, 2003, as Mr. McNally recommended. Mr. O'Bryan argued that current short-term variable interest rates are low relative to historical standards and are not representative of rates that have been typically observed or are expected in the future. He claimed that short-term rates will trend higher in the coming months and years during which the rates the Commission approves in this proceeding will be in effect. He also contended that a trailing twelve-month average interest rate smoothes out the volatility of short-term interest rates, which produces an interest rate that is more representative of a normalized short-term rate than an interest rate from any single date. (AmerenCIPS/UE Exhibit No. 12.0, p. 4; AmerenCIPS/UE Exhibit No. 25.0, pp. 3-4.)

Mr. O'Bryan's argument contains claims and assumptions that he has not substantiated. First, although Mr. O'Bryan acknowledged that past market performance is not predictive of future market performance, his argument implicitly assumes the opposite. (Tr., p. 593.) That is, by concluding that the trailing twelve-month average interest rate is representative of a "normalized" short-term rate, Mr. O'Bryan implies interest rates revert to some mean, which the trailing twelve-month average interest rate reflects. However, he did not establish that interest rates are mean reverting. Furthermore, even if interest rates were mean reverting, Mr. O'Bryan has not demonstrated that the trailing twelve-month actual interest cost as of June 30, 2002 reflects the mean for short-term interest rates. Indeed, there is no method for determining the true value of that mean.

Second, Mr. O'Bryan's assertion that a 12-month average smoothes out the volatility of interest rates is incorrect. No single interest rate estimate, be it an average of many rates or a single spot rate, reveals anything about the volatility of interest rates. The volatility in short-term interest rates will render any estimate of future short-term interest rates inaccurate to some degree. But short-term interest rates do not exhibit a repeating pattern that can be exploited to improve the accuracy of short-term interest rate forecasts. Thus, a historical average interest rate does not more accurately estimate future interest rates than the latest interest rate observation, but merely introduces outdated interest rates. (Revised ICC Staff Exhibit 13.0, pp. 3-4.) Thus, given the inability to forecast the timing, direction, or magnitude of short-term interest rate changes, the most recent observation is the most accurate, naïve estimate of future short-term interest rates available. Indeed, the Commission has concluded that "it is clear that the cost of short-term debt and variable rate long-term debt should be measured using current interest rate instead of outdated historical averages…" (Order, Docket No. 99-0534, July 11, 2000, p. 22.)

Finally, Mr. O'Bryan's arguments rest on the assumption that interest rates will rise in the near future. Despite his acknowledgement that he cannot forecast short-term interest rates with any certainty (Tr., p. 593), he implies that short-term interest rates have nowhere to go but up. That implication has already been proven incorrect, as short-term interest rates have fallen since Mr. McNally estimated the interest rate for the variable rate EI debt. (Id.) No one can forecast when interest rates will rise to, let alone above, the rate Mr. McNally recommended. Mr. O'Bryan testified that the factors that have kept rates low have lingered and that expectations of rising interest rates have not been realized in the recent past. (AmerenCIPS/UE Exhibit No. 12.0, p. 4; AmerenCIPS/UE Exhibit No. 25.0, pp. 3-4.) Until interest rates rise above the level the Commission adopts in this proceeding, the Company will continue to benefit from low interest rates. In summary, the Company is seeking to charge a rate in excess of its current cost on the speculation that its cost will rise – eventually. The Commission should not base rates on speculation.

2. Cost of Short-Term Debt

Staff proposed a 1.39% cost of short-term debt for AmerenUE. (Revised ICC Staff Exhibit 13.0, Schedule 13.1 UE.) The Company presented no objections to Staff's recommendation.

C. Cost of Preferred Stock

Staff and the Company agree that AmerenUE's cost of preferred stock is 5.19%. (*See* Staff Initial Brief Section IV.A.1.b.) However, Staff and Company do not agree on the cost of AmerenCIPS' cost of preferred stock. Company witness O'Bryan proposed a cost of preferred stock of 4.369% for AmerenCIPS. (AmerenCIPS Exhibit No. 3.5.) Staff witness McNally proposed a cost of 3.99%. (ICC Staff Exhibit 6.0, Schedule 6.5 CIPS.) Mr. O'Bryan objected to Mr. McNally's adjustment to the interest rate applied to the variable rate 1993 Auction Series. The arguments regarding this issue are identical to those for the interest rate for AmerenUE's variable rate EI bonds. Rather than repeat those arguments, Staff directs the Commission to Section IV.B.1 of this Initial Brief.

D. Cost of Common Equity

1. Companies' Recommendations

To estimate the cost of common equity for the Companies, Ms. McShane employed various methodologies, including discounted cash flow ("DCF"), risk premium, and comparable earnings analyses. (AmerenCIPS Exhibit No. 4.0, p. 2; AmerenUE Exhibit No. 4.0, p. 2.) Ms. McShane employed a sample of eight natural gas local distribution companies ("LDC Sample") in her DCF and risk premium analyses. For her comparable earnings analysis, she used a sample of 35 consumer-oriented industrial companies ("Comparable Sample"). (AmerenCIPS Exhibit No. 4.0, pp. 5-7; AmerenUE Exhibit No. 4.0, pp. 5-8).

a. DCF Analysis

Ms. McShane performed her DCF analysis on her LDC Sample. She used the average of the Institutional Brokers Estimate System ("IBES") and Zacks Investment Research ("Zacks") growth rate estimates for each company in those two samples. (AmerenCIPS Exhibit No. 4.0, p. 26; AmerenUE Exhibit No. 4.0, p. 26.) Ms. McShane estimated the current dividend yield by dividing each company's annualized 3rd quarter 2002 dividend by its average of monthly high and low stock prices for the three months ending September 30, 2002. To develop prospective dividend yield estimates for each of the companies in her samples, Ms. McShane applied each company's growth rate estimate to its current dividend yield. (AmerenCIPS Exhibit No. 4.3, Schedule 6; AmerenUE Exhibit No. 4.3, Schedule 6.) Ms. McShane then added her growth rates and prospective dividend yield estimates to produce a preliminary cost of equity estimate range of 11.5% to 11.75% for her LDC Sample.

To develop her final DCF cost of equity estimate range, Ms. McShane adjusted her preliminary cost of equity estimate using flotation cost and market value to book value adjustments. She claimed that, at minimum, a flotation cost adjustment of 50 basis points is necessary, which would produce a cost of equity estimate range of 12.0% to 12.25%. (AmerenCIPS Exhibit No. 4.0, p. 29; AmerenUE Exhibit No. 4.0, pp. 29-30.) She further claimed that to produce a fair return on book value, a larger adjustment is necessary to fully account for the deviation between book and market value. Assuming a market to book ratio of 150%, she concluded that the fully adjusted cost of equity for her LDC Sample is 14.2%. Her final DCF estimate for the cost of common equity for her LDC Sample ranged from 12.0% to 14.0%. (AmerenCIPS Exhibit No. 4.0, p. 54; AmerenUE Exhibit No. 4.0, p. 54.)

b. Risk Premium Analysis

Ms. McShane developed three risk premium estimates: one based on the capital asset pricing model ("CAPM"), one based on historic achieved risk premiums, and one based on a forward-looking risk premium. (AmerenCIPS Exhibit No. 4.0, p. 32; AmerenUE Exhibit No. 4.0, p. 32.) To each risk premium estimate, Ms. McShane added her estimate of the current risk-free rate of approximately 5.5% to 5.75%, which is based on 10-year forecasts of inflation and real economic growth as well as the historical returns on 10-year inflation-indexed government bonds. (AmerenCIPS Exhibit No. 4.0, pp. 34-35, 46; AmerenUE Exhibit No. 4.0, pp. 34-35, 47.)

c. CAPM

The CAPM can be mathematically described as follows:

$$R_E = R_F + b_e \times (R_m - R_f)$$

Where	R_E	=	Required return on individual equity security
	R_F	=	Risk-free rate
	R_m	=	Required return on the market as a whole
	b_e	=	Beta on individual equity security

As noted above, Ms. McShane used a risk-free estimate of approximately 5.5% to 5.75%. To that risk free rate, the CAPM adds a security-specific risk premium created by multiplying a market risk premium estimate by that security's beta. Ms. McShane used a sample beta of 0.65, based on the mean and median Value Line and Bloomberg betas for her LDC Sample. (AmerenCIPS Exhibit No. 4.0, p. 42; AmerenUE Exhibit No. 4.0, p. 42.)

Ms. McShane employed two methods to estimate the market risk premium in her CAPM analysis, one based on historic achieved market risk premiums, and one based on a prospective market risk premium. (AmerenCIPS Exhibit No. 4.0, p. 36; AmerenUE Exhibit No. 4.0, p. 36.) The achieved market risk premium approach uses the arithmetic average of the return premium on the S&P 500 Index relative to 20-year U.S. Treasury bonds over the 1926-2001 and 1947-2001 periods. Since the achieved market risk premium approach is based on the market premium over 20-year Treasury bonds, while Ms. McShane's risk-free rate is a 10-year estimate, the 0.4% spread between 10-year and 20-year Treasury bonds since 1993 was added. This approach produced a market risk premium of approximately 7.75% to 8.0%.

The prospective market risk premium approach is based on two separate estimates of the expected market return. (AmerenCIPS Exhibit No. 4.0, p. 40;

AmerenUE Exhibit No. 4.0, p. 40.) The first estimate was derived from a DCF analysis on the S&P 500, which produced an expected market return of 15.0%. The second estimate was derived by adding Value Line's estimate of the capital appreciation potential for its 1700 stock composite to the recent dividend yield on the composite, which also produced an expected market return of 15.0%. After subtracting Ms. McShane's 5.5% to 5.75% current risk-free rate estimate, the prospective market risk premium approach produced a market risk premium of approximately 9.4%.

Based on an achieved market risk premium of approximately 7.75% to 8.0% and a prospective market risk premium of approximately 9.4%, Ms. McShane concluded that the indicated required market risk premium is approximately 8.0% to 9.0%. That market risk premium, when multiplied by the 0.65 beta, produced a risk premium for the LDC Sample of 5.2% to 5.8%, with a midpoint of approximately 5.5%. (AmerenCIPS Exhibit No. 4.0, pp. 40-41; AmerenUE Exhibit No. 4.0, pp.41-43.)

d. Achieved Risk Premium

Ms. McShane's Achieved Risk Premium analysis used annual time series data from 1947 to 2001 for Moody's Gas Distribution Index, which Ms. McShane used as a proxy for her LDC Sample. (AmerenCIPS Exhibit No. 4.0, p. 43; AmerenUE Exhibit No. 4.0, p. 43.) To estimate the achieved risk premium, the annual realized 20-year Treasury bond return was subtracted from the concurrent annual realized return on equity for the Index for the 1947 to 2001 period. The 1947-2001 average of those annual realized risk premiums for Moody's Gas Distribution Index was 6.3%. Adding 0.4% to adjust for the historical spread between 10-year and 20-year Treasury bonds since 1993 produced a risk premium for the LDC Sample of 6.7%. (AmerenCIPS Exhibit No. 4.0, p. 43; AmerenUE Exhibit No. 4.0, p. 44.)

e. Forward-looking Risk Premium

Ms. McShane's Forward-looking Risk Premium estimate was calculated by first calculating monthly average cost of equity estimates for the LDC Sample through DCF analysis and subtracting the corresponding 10-year Treasury bond yield. (AmerenCIPS Exhibit No. 4.0, p. 44; AmerenUE Exhibit No. 4.0, p. 44.) Ms. McShane then regressed the resulting monthly risk premium against the corresponding 10-year Treasury yields, which produced the following regression equation:

$$\text{Equity Risk Premium} = 9.78 - 0.83 \times (\text{10-year Treasury yield})$$

Inserting the current long-term Treasury bond yield of 5.5% to 5.75% into the resulting regression equations produced a risk premium estimate for the LDC Sample of approximately 5.1%. (AmerenCIPS Exhibit No. 4.0, p. 45; AmerenUE Exhibit No. 4.0, p. 45.)

f. Risk Premium Analysis Conclusion

Ms. McShane's CAPM, Achieved Risk Premium, and Forward-looking Risk Premium analyses produced risk premiums for the LDC Sample of approximately 5.5%, 6.7%, and 5.1%, respectively. Based on those results, Ms. McShane concluded that an appropriate risk premium for the LDC Sample is 5.0% to 6.0%. After adding her 5.5% to 5.75% current risk-free rate estimate, Ms. McShane's Risk Premium Analysis produced a preliminary cost of equity of approximately 10.5% to 11.5%. (AmerenCIPS Exhibit No. 4.0, p. 46; AmerenUE Exhibit No. 4.0, p. 47.) To develop her final Risk Premium cost of equity estimate, Ms. McShane adjusted her preliminary cost of equity estimate using the same flotation cost and market value to book value adjustments as she used in her DCF Analysis. The flotation cost adjustment of 50 basis points produced a cost of equity estimate range of 11.0% to 12.0%. The book value to market value adjustment, assuming a market to book ratio of 150%, produced cost of equity for her LDC Sample of approximately 13.5%. Based on those results, Ms. McShane concluded that the Risk Premium estimate for the cost of common equity for her LDC Sample ranged from 11.5% to 13.5%. (AmerenCIPS Exhibit No. 4.0, p. 54; AmerenUE Exhibit No. 4.0, p. 54.)

g. Comparable Earnings Analysis

Ms. McShane's Comparable Earnings Analysis uses the average historical earned return on book value of common equity for her Comparable Sample over the period 1992-2001. (AmerenCIPS Exhibit No. 4.0, pp. 49-52; AmerenUE Exhibit No. 4.0, pp. 49-52.) The average achieved return for those 35 companies was approximately 17.5-18.0%, which she deemed to be a reasonable proxy for the required rate of return for that sample. To estimate the required return for her LDC Sample, she adjusted downward her estimate for the Comparable Sample to reflect the lower risk of her LDC Sample, as measured by the groups' median Value Line betas (0.85 for the Comparable Sample and 0.65 for the LDC Sample). With that adjustment, her Comparable Earnings Analysis produced an estimate of the required rate of return for the LDC Sample of 14.75% to 15.0%. (AmerenCIPS Exhibit No. 4.0, p. 54; AmerenUE Exhibit No. 4.0, p. 54.)

h. Recommendation

Ms. McShane's DCF, Risk Premium, and Comparable Earnings analyses produced cost of equity estimate ranges for her LDC Sample of 12.0% to 14.0%, 11.5% to 13.5%, and 14.75% to 15.0%, respectively. Based on those results, Ms. McShane concluded that the indicated cost of equity for her LDC Sample ranges from 12.00% to 14.00%, with a midpoint of 13.00%. Ms. McShane found her LDC Sample to be a reasonable proxy for AmerenCIPS in terms of overall risk. (AmerenCIPS Exhibit No. 4.0, p. 6.) Thus, Ms. McShane recommended a cost of equity of 13.0% for AmerenCIPS. (Id., p. 54.) In contrast, Ms. McShane found the LDC Sample to have slightly higher financial risk than AmerenUE. (AmerenUE Exhibit No. 4.0, p. 7.) Ms. McShane proposed a downward adjustment of 25 basis points to reflect AmerenUE's lower financial risk relative to her LDC Sample. Thus, Ms. McShane recommended a cost of equity of 12.75% for AmerenUE. (Id., p. 55.)

2. Staff's Recommendations

Staff witness McNally estimated the cost of common equity for AmerenCIPS and AmerenUE with DCF and risk premium models. DCF and risk premium models cannot be applied directly to the Companies because their common stock is not market-traded. Therefore, Mr. McNally applied those models to his Gas Sample. (ICC Staff Exhibit 6.0, p. 16.) The Gas Sample comprises nine market-traded natural gas distribution companies within the *Standard & Poor's Utility Compustat* database that had S&P credit ratings of A– or stronger and for which either IBES or Zacks growth forecasts were available.

a. DCF Analysis

DCF analysis assumes that the market value of common stock equals the present value of the expected stream of future dividend payments. Since a DCF model incorporates time-sensitive valuation factors, it must correctly reflect the timing of the dividend payments that stock prices embody. The companies in Mr. McNally's proxy sample pay dividends quarterly. Therefore, Mr. McNally applied a constant-growth quarterly DCF model. (Id., p. 18.)

DCF methodology requires a growth rate that reflects the expectations of investors. Unfortunately, investors' growth rate expectations cannot be observed. Therefore, Mr. McNally measured the market-consensus expected growth rates with projections published by IBES and Zacks. The growth rate estimates were combined with the closing stock prices and dividend data as of March 21, 2003. Based on this growth, stock price, and dividend data, Mr. McNally's DCF estimate of the cost of common equity was 10.56% for the Gas Sample. (Id., p. 21.)

b. Risk Premium Analysis

According to financial theory, the required rate of return for a given security equals the risk-free rate of return plus a risk premium associated with that security. The risk premium methodology is consistent with the theory that investors are risk-averse. That is, investors require higher returns to accept greater exposure to risk. In equilibrium, two securities with equal quantities of risk have equal required rates of return. Mr. McNally used a one-factor risk premium model, the CAPM, to estimate the cost of common equity. In the CAPM, the risk factor is market risk, which cannot be eliminated through portfolio diversification. (Id., pp. 21-23.)

The CAPM requires the estimation of three parameters: beta, the risk-free rate, and the required rate of return on the market. First, Mr. McNally used Value Line's beta estimates and a regression analysis to estimate the adjusted beta of the Gas Sample. The average Value Line beta for the Gas Sample is 0.69. The regression beta estimate for the Gas Sample is 0.50. The average of those two estimates is 0.60. (Id., pp. 28-31.) Second, Mr. McNally considered two current estimates of the risk-free rate of return: the 1.18% yield on three-month U.S. Treasury bills and the 5.24% estimated yield on thirty-year U.S. Treasury bonds. Both estimates were measured as of March 21, 2003. Forecasts of long-term inflation and the real risk-free rate suggest that the long-term risk-free rate is between 5.7% and 6.3%. Thus, Mr. McNally concluded that currently the U.S. Treasury bond yield more closely approximates the long-term risk-free rate. (Id., pp. 23-27.) Finally, to measure the expected rate of return on the market, Mr. McNally used the results of a DCF analysis conducted on the firms composing the S&P 500 Index. That analysis estimated that the expected rate of return on the market equals 14.29%. (Id., pp. 27-28.) Inputting those three parameters into the CAPM, Mr. McNally calculated a cost of common equity estimate of 10.67% for the Gas Sample. (Id., p. 31.)

c. Recommendation

Mr. McNally testified that a thorough cost of common equity analysis requires both the application of financial models and the analyst's informed judgment. A cost of common equity recommendation based solely upon judgment is inappropriate. However, because cost of common equity measurement techniques necessarily employ proxies for investor expectations, judgment is necessary to evaluate the results of such analyses. Thus, Mr. McNally analyzed his DCF and risk premium cost of equity results relative to the concurrent 6.61% yield on long-term A-rated utility bonds. Based on his analysis, Mr. McNally estimated that the cost of common equity for his Gas Sample ranges from 10.56% to 10.67%, with an average of 10.62%. (Id.)

To determine the suitability of the Gas Sample cost of equity estimate for the Companies' gas distribution operations, Mr. McNally compared the average S&P credit rating and business profile score of his Gas Sample to those he imputed for the Companies' gas distribution operations to assess their relative risk levels. The average credit rating and business profile score for the Gas Sample were approximately A and 3.1, respectively. (Id., p. 33.) Mr. McNally concluded that a business profile score of 3 would fairly reflect the business risk of both AmerenCIPS' and AmerenUE' gas distribution operations. (Id., p. 9.) In addition, Mr. McNally concluded that, on a stand-alone basis, AmerenCIPS' financial ratios reflect a mid to low A credit rating, while AmerenUE's financial ratios reflect a very strong AA rating.[4] (Id., pp. 9-11.) Thus, both the credit ratings and business profile scores indicate that the Gas Sample is a very good representative of AmerenCIPS' gas distribution operations in terms of both business risk and overall financial strength. In contrast, while the business profile scores indicate that the Gas Sample is a very good representative of AmerenUE's gas distribution operations in terms of business risk, the credit ratings indicate that the Gas Sample is more risky than AmerenUE's gas distribution operations in terms of overall

[4] In isolation, AmerenUE's June 30, 2002 capital structure reflects an AAA rating, which Mr. McNally concluded to be unnecessarily expensive. Thus, Mr. McNally imputed a capital structure for AmerenUE that is consistent with that of an AA rated utility with a business profile score of 3. (*See* Section IV.A.2 for a detailed description of this analysis)

financial strength. Thus, Mr. McNally reasoned that the investor-required rate of return on common equity for the Gas Sample is appropriate for AmerenCIPS' gas distribution operations, while a downward adjustment of 25 basis points is required for AmerenUE's gas distribution operations. Mr. McNally concluded that the required rate of return on common equity for AmerenCIPS' gas distribution operations ranges from 10.56% to 10.67%, with a recommended midpoint of 10.62%, while the required rate of return on common equity for AmerenUE's gas distribution operations ranges from 10.31% to 10.42%, with a recommended midpoint of 10.37%. (Id., pp. 31-32.)

3. Contested Issues

a. Beta Estimates

Ms. McShane maintained that the 0.50 regression beta Mr. McNally calculated for his CAPM analysis does not represent future risk perceptions and should be disregarded. She argued that the regression beta was calculated using data from a 5-year period in which there was a significant decoupling of utility stocks from the rest of the market, which caused utility betas to be understated. She also claimed that the "recent betas" provided by Value Line and Bloomberg are a superior reflection of the forward-looking beta. (AmerenCIPS/UE Exhibit No. 13.0, pp. 9-11.) In an attempt to support her claims, Ms. McShane presented a graph depicting the relationship between changes in the S&P 500 price index and the average price of the eight LDCs in her proxy sample from March 1998 through March 2003. She asserted that the graph shows that the betas for the latter half of that five-year period are much closer to the typical betas observed for gas distribution companies. She also noted that Mr. McNally discarded his regression beta in his cost of equity analysis in Docket No. 00-0802 because a few observations produced an unreasonably low beta estimate. She concluded that the same observations that led to an unreasonably low beta estimate at the time of Mr. McNally's analysis in Docket No. 00-0802 would likely still affect his current beta calculation. (AmerenCIPS/UE Exhibit No. 26.0, pp. 4-6.)

Ms. McShane's argument is speculative and flawed. First, Ms. McShane did not demonstrate that the inclusion of the "boom and bust" period from 1998 through 2000 in a beta calculation produces betas that diverge from the "typical LDC/overall equity market risk relationship." That is, Ms. McShane has failed to establish what the "typical" relationship between the Gas Sample returns and overall market returns is. In fact, one cannot make such a demonstration since true betas are unobservable and change over time. (Revised ICC Staff Exhibit 13.0, p. 17.)

Second, Ms. McShane failed to demonstrate that the Value Line and Bloomberg betas are a superior reflection of the forward-looking beta. Although, different methodologies can produce different betas because those methodologies employ different samples, the Value Line and Bloomberg methodologies are not inherently superior to Staff's methodology. For example, although the Bloomberg betas were calculated using only two years of data, and thus do not include data from the allegedly anomalous period of 1998 through 2000, that approach has the drawback of fewer observations. Moreover, the Value Line betas were calculated from essentially the same five-year measurement period as Mr. McNally's regression betas. Thus, even if betas calculated from the last 5 years are anomalous, Value Line betas would suffer the same shortcoming and would be no more representative of the investment risk of Mr. McNally's Gas Sample than the regression beta. The fact that the Value Line betas, which include data from the 1998-2000 "boom and bust" period, are actually slightly higher than the Bloomberg betas suggests that the inclusion of 1998 through 2000 data did not reduce beta estimates as Ms. McShane implied. (Id., pp. 16-18.)

Finally, the graph Ms. McShane presented uses the S&P 500 as the market proxy. (AmerenCIPS/UE Exhibit No. 26.0, p. 5.) However, Mr. McNally's beta calculation employed the NYSE index as a proxy for the market. (ICC Staff Exhibit 6.0, pp. 29-30.) Using the NYSE Composite Index as a proxy for the market return produced higher betas than using the S&P 500 Index. (Revised ICC Staff Exhibit 13.0, p. 16.) In addition, Ms. McShane acknowledged that she is not aware of the market proxy Mr. McNally used when he discarded his regression beta in Docket No. 00-0802.[5] (Tr., p. 582.) In summary, no evidence exists that Mr. McNally's regression betas, which the Commission has accepted in previous proceedings,[6] are in any manner inferior to the Value Line or Bloomberg betas Ms. McShane advocates. Therefore, Staff submits that its regression betas should not be disregarded.

b. Risk-free Rate

Ms. McShane contends that the 5.24% risk free-rate Mr. McNally used in his CAPM analysis is unsustainably low, based on long-term forecasts, and recommends a risk-free rate of 6.0% instead. (AmerenCIPS/UE Exhibit No. 26.0, p. 7.) Ms. McShane's claims are speculative. No one can forecast with any certainty the timing, direction, or magnitude of long-term interest rate changes.[7] Although, a discrepancy

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[5] The Order in Docket No. 00-0802 does not identify the market index that Mr. McNally had used to produce the regression betas he ultimately discarded.
[6] *See* for example, Order, Docket No. 00-0340, February 15, 2001, at 25.
[7] The risk-free rate issue is in most respects identical to that involving the interest rate on variable rate debt. See Section IV.B.1 for a detailed description of issue involving

exists between the real risk-free rate and inflation expectations imbedded in the long-term forecasts Ms. McShane cited and those embedded in the T-bond yield, it is important to note that T-bond yields reflect market forces, while forecasts do not. The true risk-free rate is reflected in the return investors are willing to accept in the market. As of March 21, 2003, investors were willing to accept a 5.24% return on T-bonds. (ICC Staff Exhibit 6.0, pp. 19-20.)

c. Market to Book Adjustment

Ms. McShane asserted that without an adjustment to the rate of return to recognize the deviation between current market value and book value the application of market-derived cost of equity estimates, including those produced by both the DCF and risk premium models, will significantly understate the return on original cost book value that investors require. (AmerenCIPS Exhibit No. 4.0, pp. 3-4; AmerenUE Exhibit No. 4.0, pp. 3-4.) Further, she cited James Tobin's theory that the ratio of market value to replacement cost, or the "Q ratio," should approach a value of one in a competitive environment. She concluded that a utility's replacement cost can be estimated by repricing its book value to account for past inflation, thus providing a methodology for measuring the market value of a utility that regulators should target. (AmerenCIPS/UE Exhibit No. 13.0, pp. 14-15; AmerenCIPS Exhibit No. 4.0, pp. 30-32; AmerenUE Exhibit No. 4.0, pp. 30-32.) Additionally, Ms. McShane argued that, at a minimum, a flotation adjustment should be made to market-derived cost of equity estimates in order to recognize the deviation between current market value and book value. (AmerenCIPS Exhibit No. 4.0, p. 29; AmerenUE Exhibit No. 4.0, pp. 29-30.)

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the interest rate on variable rate debt.

Ms. McShane's proposed market to book value adjustment is based on the argument that a market-derived required rate of return does not a produce a "fair" return when applied to a book value rate base if the market to book value ratio differs from one. That argument is flawed and has been rejected by the Commission. Utility stock prices will exceed their respective book values only if the investor-required rate of return has fallen or expectations of future earnings have risen. Obviously, if the investor-required rate of return has fallen, then the Commission should authorize a lower rate of return, not a higher one. Furthermore, Mr. McNally demonstrated that increased expectations of future returns due to positive deviations from test year amounts or due to earned returns from sources other than the product of rate base and rate of return do not warrant authorization of higher rates. That market values have risen to exceed book value does not mean that the amount of capital actually serving customers has increased. Under original cost ratemaking, ratepayers provide a return only on the amount of capital that is invested in assets that serve ratepayers. The Commission has consistently used the investor-required rate of return, based on DCF and CAPM methodologies, as the fair return to apply to book value rate base. It is neither fair nor appropriate to inflate that return to compensate investors for capital not invested in plant and equipment; moreover, such an adjustment would render the establishment of original cost rate base a pointless exercise. (ICC Staff Exhibit 6.0, p. 38-41.)

Ms. McShane's use of Tobin's Q merely substitutes the term "replacement cost" for market value in her market to book value adjustment argument. Thus, it suffers the same shortcomings noted above. In addition, Ms. McShane's methodology for approximating replacement cost is not consistent with Tobin's concept of replacement cost. Ms. McShane agreed that replacement cost is "the cost of construction at current prices of an asset having utility equivalent to the asset being appraised, but built with modern materials and according to current standards, design, and layout." (Tr., p. 583.) However, Ms. McShane's estimate of replacement cost simply adjusted the book value of equity for the cumulative inflation from the time the equity was added to the present. That methodology estimates the cost of <u>reproducing</u> the original assets, rather than the cost of <u>replacing</u> them with equally productive assets using modern technologies and standards. In other words, Ms. McShane's estimate of replacement cost is biased upward because it does not take into consideration technological efficiencies in methods and materials. Thus, previous arguments notwithstanding, Ms. McShane's adjustment is inaccurate and should be rejected.

Ms. McShane's flotation adjustment should also be rejected. The Companies have provided no evidence to support a flotation cost adjustment. (ICC Staff Exhibit 6.0, pp. 42-43.) Ms. McShane based her flotation cost adjustment recommendation on empirical studies of an assortment of utility stock offerings in the U.S. (AmerenCIPS Exhibit No. 4.2; AmerenUE Exhibit No. 4.2.) However, the Commission has rejected the use of such generalized flotation cost adjustments in previous cases. The Commission's Order in Docket No. 94-0065 (Commonwealth Edison Company, general increase in rates) states that "the Commission has traditionally approved [flotation cost] adjustments only when the utility anticipates it will issue stock in the test year or when it has been demonstrated that costs incurred prior to the test year have not been recovered previously through rates," and cites rate Orders from Docket Nos. 91-0193 (Central Illinois Public Service), 91-0010 (North Shore Gas), and 91-0147 (Illinois

Power) as examples of its previous decisions on the issue. Since Ms. McShane's flotation cost recommendation is not based upon evidence of issuance expenses that the Companies, themselves, have incurred but have not recovered, it should be rejected.

d. Comparable Earnings Analysis

Ms. McShane argued that regulation is a surrogate for competition. Thus, she asserted that the allowed return in this proceeding should be commensurate with the return on book equity earned by competitive industrial firms of similar risk. (AmerenCIPS/UE Exhibit No. 13.0, pp. 16-17.)

Ms. McShane's Comparable Earnings approach is badly flawed and has been rejected by the Commission in the past. Her comparable earnings methodology is based on the erroneous assumption that earned returns on book equity are acceptable substitutes for investor-required returns. There is simply no basis for this implication, since investor-required returns are only loosely related to accounting returns; they are certainly not interchangeable. For example, the return on book value of common equity is entirely unaffected by changes in the investor-required rate of return. That is, due to a decline in risk, risk premiums, or the time value of money, investors would bid up the price of a stock, thereby reducing the implied required rate of return, but the anticipated return on book equity would not change. (ICC Staff Exhibit 6.0, p. 36.)

E. Recommended Overall Rate of Return on Rate Base

Mr. McNally's overall cost of capital recommendations, incorporating his recommended capital structures, embedded costs of long-term debt, embedded costs of preferred stock, and costs of common equity equal 8.29% for AmerenCIPS and 8.19%

for AmerenUE. (ICC Staff Exhibit 6.0, Schedule 6.1 CIPS; Revised ICC Staff Exhibit 13.0, Schedule 13.1 UE.) The record demonstrates that Mr. McNally's recommendations are based upon the valid application of sound financial theory, while Ms. McShane's and Mr. O'Bryan's are not. Therefore, Staff recommends that the Commission adopt Mr. McNally's recommendations, as outlined below, to set rates in this proceeding.

AmerenCIPS' Overall Cost of Capital: Staff's Proposal

Capital Component	Ratio	Cost	Weighted Cost
Long-Term Debt	49.12%	6.74%	3.31%
Preferred Stock	6.44%	3.99%	0.26%
Common Equity	44.44%	10.62%	4.72%
Total	100.00%		8.29%

AmerenUE's Overall Cost of Capital: Staff's Proposal

Capital Component	Ratio	Cost	Weighted Cost
Short-Term Debt	1.4%	1.39%	0.02%
Long-Term Debt	43.6%	5.94%	2.59%
Preferred Stock	2.3%	5.19%	1.12%
Common Equity	52.7%	10.37%	5.46%
Total	100.00%		8.19%

V. COST OF SERVICE STUDY

A. Introduction

Both the Companies and Staff performed cost of service ("COS") studies in this proceeding; however, there is a clear demarcation between the Companies and Staff with respect to cost of service issues. Staff sponsors a reasoned cost study that is consistent not only with cost causation but also with Commission precedent. The

Companies, in contrast, present an inadequately supported cost of service approach that deviates from both costs and Commission precedent. The end result is a deeply flawed cost of service approach by the Companies that deserves to be rejected by the Commission in this proceeding.

In general, a COS study is performed to allocate costs among all customer classes to determine each customer class' respective cost responsibility for the costs imposed on the utility by that specific customer class. Rates can then be designed with the knowledge of the cost to serve each customer class. In the gas industry, COS studies are utilized as the main guide to designing rates. The Commission has consistently followed COS study principles when approving gas rates.

The uncontested cost of service issues fall into two categories. First, there are issues related to the cost allocations for propane plant, storage and working gas in storage on which the Companies and Staff witness Iannello have reached agreement. Second, all cost allocations, save those specifically identified as subject to dispute, may be considered uncontested. This would include all cost accounts except for transmission and distribution mains; Account 383, House Regulators; Account 386, Property on Customer Premises; Account 879, Customer Installation Expense; Account 902, Meter Reading Expense; and Accounts 912-916, Sales Expenses.

With regard to the allocation of the revenue requirement, the Companies and Staff agree that it should be fully cost-based, although it should be noted, that differences remain over what cost foundation is the most appropriate to use. (ICC Staff Exhibit 7.0, p. 13.)

B. Uncontested Issues

1. Allocation of Propane Costs, Storage Costs and the Carrying Cost of Working Gas in Storage between Sales and Transportation Customers

The Companies originally proposed to allocate all costs equally to both sales and transportation customers in the same rate classes. (ICC Staff Exhibit 5.0, p. 9.) Staff witness Iannello argued that it was inappropriate to allocate certain costs associated with the Companies' propane air plant and the carrying costs of working gas in storage to transportation customers. (Id., pp. 9-11.) In addition, Mr. Iannello argued that transportation customers do not receive the same level of benefits from the use of Company-owned storage and, therefore, should not be allocated the same level of storage costs as sales customers. (Id., p. 15.)

Staff witness Iannello testified that the Companies' propane air plant is used to provide an additional source of supply to meet demand on peak days. The cost of propane fuel is recovered from sales customers through the Companies' PGA clause. Mr. Iannello stated that the Companies' tariffs do not provide transportation customers with access to the Companies' propane supplies. (Id., p. 10) As a result, transportation customers receive no benefit from the Companies' propane-air plant and, therefore, should not be allocated any of the costs associated with the plant. (Id.)

Mr. Iannello testified that working gas is the natural gas that storage facility operators anticipate using or cycling in the normal operation of a storage reservoir during the withdrawal season. (Id., p. 9.) Mr. Iannello argued that the Companies are relieved of the obligation to store a portion of gas on behalf of customers when they choose transportation service. This decrease in the need to maintain storage inventories results in a reduction in the Companies' carrying cost associated with working gas in storage. (Id., pp. 9-10.) That is, transportation customers directly assume the carrying costs associated with working gas in storage when they deliver gas to their storage banks. Mr. Iannello argued that it is, therefore, inappropriate to allocate the carrying costs of working gas in storage to transportation customers. (Id.) He also noted that the Commission had recently ordered other gas utilities to offset the costs associated with small volume transportation programs with the reduction in carrying costs of working gas in storage that occurs as a result of customers switching from sales to transportation service. (Id., p. 10.)

Mr. Iannello recommended that the Companies develop a separate set of base rates for sales customers and transportation customers, allocating propane plant and related expenses and the carrying cost of working gas in storage to sales customers only. (Id., p. 11.) The Companies adopted Mr. Iannello's proposed allocation of propane plant and related expenses and the carrying cost of working gas in storage and included these allocations in their final calculation of rates. (AmerenCIPS/UE Exhibit No. 20.0, pp. 9-10; AmerenCIPS/UE Exhibit No. 34.1) No other party opposed Mr. Iannello's recommended allocation of these costs.

Mr. Iannello identified three potential benefits associated with the use of natural gas storage facilities. He stated that storage could provide a seasonal hedge by allowing shippers to inject gas into storage during the injection season (roughly April through October), when spot prices are typically low, and withdraw gas from storage during the withdrawal season (roughly November through March), when spot prices are typically high. Storage facilities also allow shippers to reconcile daily imbalances between usage and deliveries. Finally, storage can reduce the need for more expensive pipeline capacity during periods of peak demand. (Id., p. 15.)

Mr. Iannello argued that, under the Companies' current transportation tariffs, transportation customers are able to use their storage banks for balancing and peak shaving but are precluded from using their storage banks for seasonal hedging. (Id., p. 11.) This is in contrast to the Companies' use of storage to serve sales customers. CIPS uses on-system storage to provide seasonal hedging on behalf of sales customers. Despite the limited access to storage that transportation customers receive vis-à-vis sales customers, CIPS originally proposed to allocate storage plant and related expenses equally to sales and transportation customers in the same rate classes. (Id., p. 9.) Originally, Mr. Iannello argued that transportation customers should be provided access to storage that is commensurate with the storage-related costs that are allocated to transportation customers. (Id., pp. 18-19.)

The Companies accepted Mr. Iannello's arguments that transportation customers do not receive the same access to storage as sales customers. (AmerenCIPS/UE Exhibit No. 20.0, p. 9.) Instead of proposing revisions to the current terms governing storage use in the Companies' transportation rider, CIPS proposed to reallocate costs associated with storage plant and related expenses to reflect the lower level of storage service offered to transportation customers. UE has no on-system storage facilities.

CIPS originally proposed to allocate 24% of storage plant and related expenses to transportation customers. In response to Mr. Iannello's concerns, CIPS determined that only 21% of storage plant and related expenses should be allocated to transportation customers. The remaining storage plant and related expenses would be allocated to sales customers. (AmerenCIPS/UE Exhibit No. 32.0, p. 3.) Mr. Iannello agreed to CIPS' storage cost allocation in lieu of his recommendation to revise various rules governing the use of storage banks and deliveries in the Company's transportation tariff. (Tr., p. 233-234.) No party opposed CIPS' proposed reallocation of storage plant and related expenses.

C. Contested Issues

1. Allocation of Transmission Plant

Staff's proposed Average and Peak ("A&P") allocator for transmission plant should be adopted in this proceeding. First and foremost, it more appropriately reflects costs than the Companies' proposal. Second, Staff's study follows Commission precedent. The Companies' proposed non-coincident peak allocator is deficient in both respects.

The A&P is a two-part allocator that allocates average system demands one way and the difference between the system peak and the system average demand in another way. The first part, the average component of system demand is allocated according to the average annual demands of rate classes. The second part, the difference between the system peak and the system average demand, is allocated on the basis of class contribution to peak demand. (ICC Staff Exhibit 7.0, pp. 7-8.)

The A&P approach recognizes that transmission plant is built for two purposes. One is to meet peak demands, not just for individual classes, but for the system as a whole. Second, the A&P recognizes that transmission plant investment cannot be justified on a financial basis by the demands of a single peak day. Rather, it requires demands throughout the year in order to be built. The A&P properly includes an average component to reflect the role of year-round demands in shaping transmission investments. (Id., p. 8.)

As a further advantage, Staff's proposed A&P allocator is consistent with Commission precedent. (Id., p. 9.)

The Companies, for their part, seek to justify the proposed non-coincident peak allocator with two arguments. First, they contend that the non-coincident peak allocator rests on a substantial body of theory, including the 1981 NARUC Gas Rate Design Manual. (AmerenCIPS/UE Exhibit No. 20.0, p. 3.) The Companies further argues that non-coincident peaks recognize that transmission costs are incurred to meet the demands of all customers and ensure that all will pay their "equitable share" of the costs. (Id.)

Both arguments present problems. The reference to the NARUC manual offers no guidance because the more recent 1989 NARUC manual also discusses Staff's A&P approach and expresses no preference for one over the other. (ICC Staff Exhibit 14.0, p. 3.)

Ameren also errs by stating that ensuring everyone will pay is an appropriate equity standard. In fact, equity is better served by adhering to the longstanding Commission standard of basing rates on costs. (Id., p. 4.) When judged against this standard, the Companies' proposed non-coincident peak allocator falls short.

The non-coincident peak approach deviates from costs because transmission investments are driven by peak demands, rather than the non-coincident demands used in the Companies' proposed allocator. (Id.) This is an issue on which even the Companies agree. Witness Carls was given an example where the Companies had a total peak demand of 100 units and non-coincident peak demand of 120 units. He was then asked which demands would the Companies design its transmission system to meet, 100 or 120 units? (Tr., pp. 171-172.) He responded as follows:

> A. The Company would use the 100 figure I would imagine with a sufficient safety factor.
> Q. Because that's the actual expected peak?
> A. Because that's the actual expected peak.

2. Allocation of Distribution Plant

The Commission should adopt Staff's A&P allocator for distribution plant as well. This conclusion reflects the same arguments that support the use of the A&P for transmission plant. As previously explained, the A&P is both cost-based and consistent with Commission precedent.

The Companies propose to use the Average and Excess Allocator ("A&E") for distribution plant. The allocator consists of two components. One component is shaped by average demands for individual customers and the system as a whole. The second component is determined by peak demands, actually the difference between peak demands and average demands. The average component allocates system average demand by the ratio of average demand for individual classes to the sum of the average demands for all rate classes. Then, the difference between system peak demand and system average demand is allocated by the difference between individual class noncoincident peak demands and class average demands divided by the sum of the differences between noncoincident peak demands and average demands for all rate classes. (ICC Staff Exhibit 7.0, pp. 5-6.)

The allocator has both good and bad features. By relying on average demands, the A&E does recognize that distribution systems are erected not just to serve peak demands, but to meet the needs of customers throughout the year. However, the Excess component of the rate presents problems. For one, this component is shaped by noncoincident peak demands even though distribution investments are shaped by peak demands. This creates a mismatch between cost causation and cost allocation under the A&E approach. (Id., pp. 6-7.)

A second problem is that the A&E focuses on allocating the difference between peak and average demands, rather than peak demands only. By focusing on the excess component, the Average and Excess allocator overstates the role of the excess in shaping distribution costs. This creates a further disparity between cost allocation and cost causation. (Id., p. 7.)

Furthermore, unlike Staff's proposed A&P allocator, the A&E deviates from Commission precedent.

These arguments demonstrate that Staff's proposed A&P allocator provides a more appropriate foundation for allocating distribution plant investments than the Companies' A&E allocator and should be used for ratemaking in this proceeding.

3. Allocation of Account 383

The Companies' proposed allocator for Account 383 suffers from a number of deficiencies. For one, the Companies have chosen to deviate from Commission precedent without providing a meaningful explanation why in its filing. Second, Ameren has failed to establish that it appropriately relies on cost causation principles. In addition, Ameren has fallen short by failing to adequately support this proposal during the course of this proceeding.

The failure of the Companies' filing to explain the divergence from current Commission policy is admitted directly by witness Difani as follows:

> Q. On Page 3 of his direct testimony, Mr. Lazare states that the Company has deviated from the allocation method approved by the Commission in its most recent case and the Company did not explain why the currently approved method is inappropriate for the current proceeding. Do you agree?
>
> A. In general, Mr. Lazare's statements are correct. (AmerenCIPS/UE Exhibit 20.0, p. 2.)

Thus, the Companies admit the deficiency in their case which, it should be noted, applies not just to this cost account, but to all cost allocations Ameren has proposed that deviate from current Commission policy.

What discussion the Companies do provide in their filing with regard to this account and other customer-related accounts is limited to the following by witness Difani:

> I used a services factor, a meter factor, and a regulator factor to allocate these plant accounts. The services factor is based on estimates of average costs for each class' service pipe. The meter factor is based on the individual coding of meters in the Company's billing system by customer class, and using the current cost of each meter code with installation labor included. I directly assigned a portion of metering and billing investment associated with the Metscan System and the Unbundled Services Management System to the metering plant account. The regulator factor is based on an average size regulator for each meter code. (AmerenCIPS/UE Exhibit No. 9.0, p. 7.)

This perfunctory discussion identifies a total of three factors proposed for the Companies' customer-related distribution plant but does not explain which factor or factors are used for individual accounts. Nor is any support provided for these allocators in Mr. Difani's direct testimony. (ICC Staff Exhibit 14.0, p. 7.)

Mr. Difani presents a more specific discussion of Account 383 in Rebuttal which makes reference to the use of a "comprehensive study" to allocate these costs. (AmerenCIPS/UE Exhibit No. 20.0, pp. 6-7.) However, an explanation of this "comprehensive study" is not forthcoming.

In short, the Companies have belatedly cobbled together weak arguments and unsupported assertions on behalf of their proposed allocation of Account 383. As a result, Ameren fails to demonstrate why the Commission should revisit its conclusions in the Companies' previous rate cases on these matters. The only reasonable course in this situation is for the Commission to reaffirm its previous conclusions on these costing issues by employing the Staff-proposed study to design rates in this case.

4. Allocation of Account 386

Similar problems arise with the Companies' proposed allocation of Account 386, Property on Customer Premises, as exist for Account 383. Again, the Companies have chosen to deviate from the Commission-approved allocator for these costs without providing any meaningful explanation why. (AmerenCIPS/UE Exhibit No. 20.0, p. 2.) The only reference to this account in the Companies' direct filing is the previously cited general discussion by Mr. Difani of customer-related costs, which fails to address Account 386 costs in particular. (ICC Staff Exhibit 14.0, p. 7.)

When the Companies do address these costs specifically, their argument amounts to a set of unsupported assertions by Mr. Difani:

> [T]he Commission should adopt the Company's allocators based on the use of actual cost data for the residential class and a distribution plant allocator for the remaining classes. It is clear that the Company's allocation more closely tracks the costs incurred by class in this account than does the Staff's. (AmerenCIPS/UE Exhibit No. 20.0, p. 7.)

Despite this claim, the Companies fail to identify what actual cost data is used for their proposed allocator. (ICC Staff Exhibit 14.0, p. 8.) Nor, do they explain the reasonableness of combining this actual cost data for residential customers with a distribution plant allocator for others.

In contrast, Staff proposes a reasonable allocation based on meters for all customers which is consistent with Commission precedent and should be adopted by the Commission in this case.

5. Allocation of Account 879

The Staff-proposed allocator on the basis of service lines should be adopted over the Companies' allocator on the basis of previously allocated distribution plant. While Staff's proposed allocation is consistent with Commission precedent, the Companies propose to deviate from that precedent with an allocation based on belated and incomplete support. Specifically, witness Difani fails to explain why Account 879 Customer Installation Expenses which includes activities such as "leak testimony, re-lighting pilot lights, activating and disconnecting meters" is more related to previously allocated distribution plant than service lines as determined by the Commission in the Companies' previous dockets. (ICC Staff Exhibit 14.0, p. 8.) The Companies' argument fails to provide a reasonable basis for deviating from Commission precedent on this issue.

6. Allocation of Account 902

While Staff and the Companies propose the same meter-based allocator for AmerenUE (AmerenCIPS/UE Exhibit No. 33.0, p. 6), the Companies propose an alternative allocator based on a "meter reading time study" according to witness Difani. (AmerenCIPS/UE Exhibit No. 20.0, p. 8.) Again, the Companies fail to discuss this issue in their filings. (Id., p. 2.) In addition, the Companies' discussion in rebuttal testimony is incomplete, lacking any meaningful discussion of the proposed "meter reading time study." In this case as well, the Companies have failed to provide sufficient basis to deviate from Commission precedent as reflected in Staff's meter-based allocator.

7. Allocation of Account 912-916

The Commission should adopt Staff's proposed allocation of these expenses on the basis of revenues rather than on the basis of previously allocated customer accounts expenses as the Companies propose. The problems with the Companies' proposals again center on the issue of late and incomplete support. For Accounts 912-916, the only support the Companies can provide for their proposed allocation methodology is Mr. Difani's statement that "the Company's use of previously allocated customer service expenses for allocating expenses in these accounts more closely reflects cost causation and ensures that all customers pay an equitable share of expenses in these accounts." (Id., p. 9.) This is a simple statement unaccompanied by any tangible support and does not justify a deviation from the current Commission-approved allocation of these costs. (ICC Staff Exhibit 14.0, p. 8.)

8. Allocation of Storage Costs Between Sales and Transportation Customers

The Companies and Staff are in agreement with regard to this issue. See discussion, in Section V.B.1., *supra*.

9. Allocation of Revenue Requirement

While both the Companies and Staff propose that the revenue requirement be allocated on the basis of cost, the more appropriate foundation to use is the cost of service methodology proposed by Staff in this case. For the reasons previously discussed, Staff's cost study approach provides the most appropriate foundation for allocating the revenue requirement in this proceeding. Therefore, the specific method of allocating the revenue requirement proposed by Staff should be adopted in this proceeding. (ICC Staff Exhibit 7.0, p. 13.)

VI. RATE DESIGN; TARIFF TERMS AND CONDITIONS

A. Introduction

Based on the different cost of service studies proposed and different rate design proposals, it appears that all rates are on one level or another contested in this proceeding.

B. Uncontested Issues

1. Transportation Specific Administrative Charges

The Companies' current Rider T, Transportation Service, ("Rider T") contains a transportation-specific administrative charge of $60.00 per month per meter. (ICC Staff Exhibit 5.0, p. 6.) This administrative charge is assessed in addition to the customer and delivery charges in the standard rates that apply to both sales and transportation customers. The administrative charge is designed to recover labor costs associated with various gas transportation administration functions. These costs are largely fixed and do not vary with the number of customers that choose transportation service. (Id.)

Staff witness Iannello noted that these fixed administrative costs are allocated to and recovered from a relatively small number of customers that choose transportation service even though a much larger number of customers are eligible for transportation service. (Id., p. 7.) The design of the administrative charge results in an increase in revenues when additional customers choose transportation service even though the Companies do not incur significant cost increases as a result of such a migration from sales to transportation service. (Id.) Therefore, the current design of the transportation-specific administrative charge unduly discourages smaller volume customers, who might otherwise be able to achieve significant gas cost savings, from choosing transportation service.

In order to rectify this situation, Staff witness Iannello recommended that the largely fixed administrative costs associated with the transportation service be allocated to all customer's eligible to take transportation service. The costs would be allocated based on each rate class' share of the total number of transportation customers. The costs would be recovered through the Customer Charge of each eligible rate class. Eligible rate classes include Rate 11, Rate 20, and Rate 21 in CIPS' service territory and Rate 2, Rate 3, and Rate 4 in UE's service territory. (Id., p. 8.) Staff witness Lazare recommended that interruptible rates be eliminated. If the Commission adopts his position, the administrative costs should be allocated to the remaining eligible classes.

The Companies adopted Mr. Iannello's proposed allocation of the transportation-specific administrative costs and included the proposal in their final calculation of rates. (AmerenCIPS/UE Exhibit No. 18.0, p. 2; AmerenCIPS/UE Exhibit No. 34.1.) No other party opposed Mr. Iannello's recommendation.

C. Contested Issues

1. Residential Customer Charge

The evidence indicates that the Companies' proposed method of developing customer charges applied to the cost study proposed by Staff should be adopted in this proceeding. That means basing the AmerenCIPS customer charge on full embedded costs but limiting the increase in the AmerenUE charge to less than full cost to avoid potential adverse customer impacts.

CUB has proposed an alternative methodology based on an avoided cost methodology (CUB Exhibit 1.0, p. 20), which Staff has not accepted for this case. While Staff reserves the right to revisit the customer charge issue in future cases, Staff has focused in this case on embedded costs and customers impacts and found the Companies' method reasonable on both counts. (ICC Staff Exhibit 7.0, p. 16).

Finally, it should be noted that Staff recommends a significantly lower revenue requirement than the Companies which, if adopted, would reduce the customer charge below the Companies' proposal.

2. Residential Usage Charge, Flat vs. Declining Block

The evidence in this proceeding clearly supports Staff's proposal for a flat rate rather than the declining block proposed by the Companies. Staff's proposal is supported by arguments that take into account both the direct and environmental costs associated with the provision of natural gas. The Companies, for their part, base their proposed declining block rate on flawed arguments concerning (1) revenue stability and (2) potential revenue losses.

Staff has two central concerns about the declining block structure for delivery charges. First, it has not been cost-justified for AmerenCIPS. According to the AmerenCIPS, the proposed customer charge recovers all customer costs for the class, which means that only demand-related costs will be recovered by the delivery charge. The Company has provided no evidence why those demand-related costs should be recovered unequally over distribution therms. (Id., p. 17.)

The second concern, which extends to both AmerenCIPS and AmerenUE, is that the declining block structure does not convey to ratepayers the proper price signals to conserve energy. Under this structure, the first 90 therms of gas are priced at a higher rate than subsequent usage. In other words, as consumers move into the higher block, the per-therm price declines. This lower tailblock rate gives ratepayers an incentive to increase their gas consumption, rather than conserve. This is an inappropriate price signal to send to consumers. (Id.)

The tailblock rate is too low because it fails to reflect all costs to society of consuming gas. In addition to the direct costs, there are indirect environmental costs that are not directly captured in the price of gas. Each therm of gas consumed has an adverse effect on the environment and therefore imposes an environmental cost. (Id., p. 18.)

One such effect is the contribution of gas consumption to the problem of Global Warming. The contribution by natural gas and other fossil fuels to Global Warming is discussed by the Energy Information Administration ("EIA") as follows:

> Most greenhouse gases occur naturally, but concentrations of carbon dioxide and other greenhouse gases in the Earth's atmosphere have been increasing since the Industrial Revolution with the increased consumption of fossil fuels and increased agricultural operations. Of late there has been concern that if this increase continues unabated, the ultimate results could be that more heat would be trapped, adversely affecting Earth's climate (Energy Information Administration, Natural Gas 1998: Issues and Trends, p. 55). (Id.)

This concern is joined by the Environmental Protection Agency which states as follows:

> According to the National Academy of Sciences, the Earth's surface temperature has risen by about 1 degree Fahrenheit in the past century, with accelerated warming during the past two decades. There is new and stronger evidence that most of the warming over the last 50 years is attributable to human activities. Human activities have altered the chemical composition of the atmosphere through the buildup of greenhouse gases – primarily carbon dioxide, methane, and nitrous oxide. The heat-trapping property of these gases is undisputed although uncertainties exist about exactly how earth's climate responds to them. (Id., pp. 18-19.)

The evidence indicates that natural gas plays a significant role in Global Warming, contributing an estimated 22% of carbon dioxide emissions by primary fuels in the United States.[8] Furthermore, the EIA notes that gas contributes to the atmospheric buildup of methane, a second contributor to Global Warming. Methane is a

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[8] (http:www.eia.doe.gov/oiaf/1605/ggccebro/chapter1.html)

potent greenhouse gas, considered to be 21 times more effective than carbon dioxide in trapping atmospheric heat. So, while methane accounts for only 0.5% of U.S. emissions of green house gases, it explains 10% of the greenhouse effect caused by fossil fuels in the U.S. The major constituent of natural gas is methane. So whenever gas is leaked or vented, methane escapes to the atmosphere. The net result is that gas accounts for approximately 21% of methane emissions in the U.S. (Id., pp. 19-20.)

This is not the only environmental cost associated with natural gas. The combustion of natural gas in the air also produces carbon monoxide, and nitrogen oxides, which contribute to the formation of ground level ozone, smog and acid rain. (Id., p. 20).

The conclusion that gas consumption impacts the environment is reached not just by Staff, but by the Companies as well. Ameren stated: [t]he consumption of all fossil fuels impacts the environment to some degree as the result of the release of emissions. (Id.)

These environmental costs have direct implications for gas usage and rate design. From a usage standpoint, it is essential that ratepayers avoid wasteful and inefficient usage which unnecessarily exacerbates the environmental impacts. This means that rates should send signals that encourage ratepayers to conserve, rather than consume more. Therefore, the Companies' declining block proposal should be replaced by a flat delivery rate. (Id, p. 21.)

The Companies present three arguments on behalf of their declining block structure. One seeks to justify declining blocks on the basis of costs. The second argument rests on the notion of revenue stability. Third, Ameren contends that the focus of Staff's proposal on encouraging conservation will reduce usage and cause the Companies to under-earn.

The costing argument as presented by Ameren witness Carls assumes that most delivery costs are fixed and do not vary with consumption levels. These costs, he contends, would be appropriately recovered through fixed charges were it not for "customer resistance." (AmerenCIPS/UE Exhibit No. 21.0, p. 5.) The next best approach, according to Mr. Carls is to recover the remaining fixed costs in the initial monthly usage levels, resulting in a declining block rate). (Id., p. 6.)

This argument is fundamentally flawed. Mr. Carls errs in assuming that all fixed costs should be treated in a similar matter from a cost standpoint and collectively recovered through fixed (i.e., customer) charges. In fact, significant differences exist between fixed costs on the Ameren system. While some fixed costs are clearly customer-related and appropriately recovered through monthly customer charges, other fixed costs are shaped by customer's demands and appropriately recovered in variable charges. That means recovery through delivery charges for customers with usage meters. (ICC Staff Exhibit 14.0, p. 12.)

Staff has provided a simple example to illustrate the problem with Ameren's fixed charge argument. If Customer A consumes ten times as much gas as Customer B, Customer A will, on average, require significantly more demand investments to receive service. However, if all demand-related fixed costs are rolled into the customer charge, then Customer A and Customer B will assume equal financial responsibility for these investments, which is clearly unfair to Customer B from a cost standpoint. That is why demand-related fixed costs are more appropriately recovered through the usage, rather than the customer, charge. (Id.)

The Companies' revenue stability argument for declining block rates flows directly from their cost argument that fixed costs should not be recovered in tailblock delivery rates. Mr. Carls sums this issue up in his Rebuttal Testimony:

> Again, and I cannot overemphasize this, a principal justification for the Company's proposed declining blocked rate structure is that it supports revenue stability by allowing fixed costs that are not recovered in the customer charge to be recovered from usage billed in the initial rate block. (AmerenCIPS/UE Exhibit No. 21.0, p. 6.)

Mr. Carls' revenue stability argument is clearly inappropriate. The Companies are apparently not satisfied with being the monopoly provider of gas service in their local service territories. Ameren wants the further certainty of receiving as much revenue as possible from these captive customers up front. In essence, Mr. Carls' rate design seeks to advance the interests of the Companies at the expense of ratepayers and society as a whole. A more appropriate objective for designing rates is to send appropriate price signals to ratepayers about the cost of providing gas service. That is the goal of the flat rate proposed by Staff. (ICC Staff Exhibit 14.0, p. 14.)

The argument that Staff's flat rate proposal will create revenue shortfalls for the Companies is presented by Mr. Carls. He states that Staff's flat rate proposal, by encouraging conservation, will guarantee that Ameren does not earn its full return. (AmerenCIPS/UE Exhibit No. 21.0, p. 7.) This argument is deficient on two counts. First, it focuses on the impact of Staff's proposal on the tailblock rate but conveniently ignores the virtually identical impact of the Companies' proposed rate increase on that same rate. The similarities between the two are revealed by a comparison of the

Companies' proposed tailblock rate with the effect on current rates of Staff's flat rate proposal. The analysis indicates that replacing the current declining block rate for AmerenCIPS with a flat rate raises the tailblock rate from the existing 11.64 cents per therm to 14.33 cents per therm. In comparison, the Companies' proposed rate increases includes a tailblock rate of 14.26 cents per therm for these customers. For AmerenUE, the proposed increase has a greater impact on the tailblock rate than Staff's flat rate proposal, raising it to 19.42 cents per therm, compared with an increase to 17.55 cents per therm due to the adoption of a flat rate. The Companies' proposal could further impact consumption because it also includes significant increases in the customer charge and the first block usage charge for Residential customers. (ICC Staff Exhibit 14.0, pp. 15-16.)

Thus, while witness Carls predicts dire consequences from a consumption standpoint of Staff's tailblock rate proposal, he voices no such concern about the consumption impact resulting from his proposal that has a virtually identical impact on the tailblock rate. This one-sided and arbitrary argument should be rejected by the Commission. (Id., p. 16.)

Finally, it should be remembered that the Commission can mitigate any potential impacts by adopting the revenue requirement proposed by Staff in this case. That would reduce the tailblock charge under Staff's flat rate proposal and thereby address Mr. Carls' concern about the impact on consumption. (Id.)

3. Size of Residential First Block

Staff has not focused on this issue because it believes the two-block structure should be eliminated in favor of a single block rate.

4. Grain Dryer Rate

The issue raised by BEAR is whether there should be a separate rate for Grain Dryers. BEAR witness Smith has argued that these customers as off-peak users have unique load shapes that translate into lower costs and justify a unique rate. (BEAR Exhibit 1, pp. 3-4.) The Companies oppose this proposal, arguing that sufficient data does not exist for the development of such a rate. (AmerenCIPS/UE Exhibit No. 21.0, p. 10.) The Companies also contend that the argument concerning the load shape of grain dryer customers does not justify the separate rate. (Id.) The Companies further contend that the BEAR proposal represents a return to the now-discredited concept of end-use rates. (Id.)

Staff has not addressed this issue in testimony or taken a position on the issue in this case.

5. Elimination of Interruptible Service

Staff's proposal to eliminate interruptible service should be adopted by the Commission. The Ameren system derives no tangible benefits from the continuation of interruptible service and interruptible customers have not been interrupted since at least January 1997. Thus, interruptible service amounts to a one-sided benefit for interruptible customers; essentially firm service at a discounted rate.

There are currently 13 non-residential AmerenCIPS customers and 3 non-residential AmerenUE customers on interruptible service. (AmerenCIPS Exhibit No. 10.0, p. 12; AmerenUE Exhibit No. 10.0, p. 12.) These customers receive lower rates for gas service than firm customers, but, in return, their service may be interrupted when capacity constraints arise on the AmerenCIPS and AmerenUE systems.

The key to this rate option is the possibility of interruption. If that possibility disappears, then the justification for interruptible service disappears as well. Information provided by the Companies in the discovery process indicates that interruptible customers have not received a single service interruption over the last five years. Thus, these customers are, for all intents and purposes, receiving firm service while enjoying the benefit of lower interruptible rates. When there is no justification from a system standpoint, interruptible rates amount to an unwarranted subsidy from firm customers to interruptible customers. (ICC Staff Exhibit 7.0, p. 10.)

This problem may be remedied by eliminating interruptible service. Since these customers are essentially receiving firm service, they should be treated as firm customers for the purpose of allocating costs and designing rates.

The Companies respond to this proposal by trying to justify the current levels of interruptible service for both AmerenCIPS and AmerenUE. Witness Carls provides one set of arguments for AmerenUE and another for AmerenCIPS. His argument for AmerenUE focuses on rate impacts. He contends that the existing AmerenUE customers should remain on interruptible service to prevent the impact of a switch to firm service. (AmerenCIPS/UE Exhibit No. 21.0, p. 4.) Mr. Carls focuses on costing issues for AmerenCIPS. He contends that interruptible service is necessary to address a localized distribution system constraint. (Id., p. 2.) He contends that the elimination of interruptible service for these customers would require the Company to make capital improvements to remove system constraints. (Id., p. 3.)

Mr. Carls' arguments present problems. His concern about rate impacts does not justify continuing interruptible service for AmerenUE customers. The appropriate foundation for ratemaking is cost of service, not customer impacts. If the cost of serving interruptible customers is no different from the cost for firm customers then fairness dictates that the rates be the same. Otherwise, the Company would be unfairly discriminating in favor of interruptible customer over firm customers. (ICC Staff Exhibit 14.0, p. 10.)

Mr. Carls' argument for AmerenCIPS amounts to no more than an assertion that AmerenCIPS cannot provide assurances of serving all demands on a firm basis. However, his statement is undermined by the available evidence which, as previously noted, demonstrates that the Company has failed to curtail any customers since 1997, a period of more than six years. During that time, Illinois has experienced some extreme weather, including the third coldest December since 1895 according to the National Oceanic and Atmospheric Administration. (Id., p. 11.) Nevertheless, the Company has managed to serve the demands of all customers, firm and interruptible, during this time. The Company has provided no evidence why it should be unable to serve all demands into the foreseeable future. (Id., pp. 10-11.)

Given the available evidence on this issue, the only reasonable action is to eliminate interruptible service on the AmerenCIPS system.

6. Reduce Restrictions on Access to Interruptible Service

Staff's argument that Interruptible Service should be eliminated means that Staff would oppose any reductions in restrictions on access to this service.

7. Elimination of Minimum Monthly Charges

Staff has not taken a position on the issue in this case.

8. Group Balancing Service

Staff witness Iannello and MEC witness Jansen recommended that the Companies implement a group balancing service that would allow alternative gas suppliers to group transportation customer accounts for the purposes of nominating gas to the Companies' systems, injecting gas into and withdrawing gas from storage banks, and performing daily balancing. (ICC Staff Exhibit 5.0, p. 19; MEC Exhibit A, p. 3.) Staff witness Iannello recommended a group balancing tariff to mitigate the impact of the Companies' strict limitations on transportation customer deliveries and bank use, which were implemented as a result of a filing on May 16, 2001. (ICC Staff Exhibit 5.0, p. 13.)

Under the Companies' current transportation tariffs, suppliers are not permitted to group customer accounts. Rather, suppliers are required to make an individual nomination for each transportation customer. Bank withdrawals and injections are tracked separately for each account. Except in the case of multiple accounts owned by the same customer, transportation customer deliveries and usage must be balanced at the individual account level regardless of the number of customers served by a supplier. (Id., pp. 19-20.)

Staff witness Iannello argued that implementation of a group balancing service would streamline the nomination process by reducing the administrative burden of dealing with transportation customers at the individual account level. In addition, group balancing would eliminate the assessment of penalties in cases where aggregate transportation customer activity has no adverse impact on the system as a whole. (Id., pp. 20-22.)

The Companies adopted Staff and MEC's recommendation to implement a group balancing service and made various proposals as to how the group balancing tariff should be structured. (AmerenCIPS/UE Exhibit No. 18.0, pp. 8-10.) The Companies proposed implementing a pilot program no later than July 1, 2004 that would become effective September 1, 2004. Under the Companies' proposal, only customers on transportation service as of September 1, 2003, would be immediately eligible for group balancing service. Customers on sales service as of September 1, 2003 would be able to apply for group balancing service on September 1, 2005. (Id., p. 9.) The Companies also state that they anticipate charging a fee for group balancing service. (Id., p. 10.)

Staff does not necessarily agree with the Companies' position on customer eligibility for group balancing or the need to charge a fee for group balancing. (ICC Staff Exhibit 12.0, p. 12.) However, there is no need to argue over the details of the Companies' group balancing service in the instant proceeding.

The details of the Companies' proposed group balancing service should be addressed either through a workshop process before the Companies file a group balancing tariff or litigated in a Commission proceeding after the Companies file a group balancing tariff. Staff witness Iannello recommends that the Commission require the Companies to file tariffs setting forth the terms of the group balancing service no later than July 1, 2004. He noted that the Companies have already committed to make such filings, so they should have no objection to such a requirement. (Id., p. 12.) In hopes that litigation of the Companies' group balancing tariff filing could be avoided, Staff witness Iannello also recommended that the Commission require the Companies to hold at least three workshops during the period of January 2004 through March 2004, allowing interested parties to provide input into the development of the Companies' group balancing service. (Id., p. 12) Finally, Mr. Iannello recommended that the Commission refrain from ordering the Companies to implement any specific terms or conditions related to group balancing service in the instant proceeding, leaving the details to be sorted out in the workshop process and, if necessary, through a Commission-ordered proceeding. (Id.)

While the Companies are receptive to a workshop process aimed at developing group balancing service, the Companies object to Mr. Iannello's proposal for the Companies to hold three workshops during the period of January 2004 through March 2004. The Companies argue that they should be afforded the discretion to decide when and how many workshops are needed. (AmerenCIPS/UE Exhibit No. 32.0, pp. 4-5.) While the Companies request that they be afforded such discretion, they also propose to hold the workshops during the period of November 2003 through March 2004 and suggests that only one or two workshops will likely be necessary. (Id.) While Staff originally proposed three workshops; however, Staff did not envision the Companies being required to hold all three workshops if all parties were satisfied after the completion of one or two workshops. With respect to the time period, the end date of March 2004, proposed by both Staff and the Companies, is the binding constraint since the Companies would be required to file tariffs by July 1, 2004. Staff welcomes the Companies' proposal to include November and December in the workshop process time frame.

9. Bank Balance Withdrawal Limit

Several parties took issue with the limitations on transportation customer deliveries and bank use. Mr. Iannello described a bank as essentially a storage account for transportation customers that may be utilized to absorb differences or "imbalances" between a transportation customer's daily deliveries and daily usage. He also stated that banks could potentially aid transportation customers in peak shaving and seasonal hedging, depending on the rules that govern bank use. (ICC Staff Exhibit 5.0, pp. 11-12.)

Mr. Iannello addressed the detailed provisions governing transportation customer banks as follows:

> A bank is essentially a storage account for transportation customers. Banks are utilized to absorb differences or "imbalances" between a transportation customer's daily deliveries and daily usage, provide additional supplies to meet peak demand, and provide for seasonal hedging. Bank is defined in Rider T as the amount in therms of a transportation customer's daily delivery in excess of the customer's daily usage, plus the prior days' Bank balance.
>
> Rider T limits deliveries to the Company's system to 120% of a customer's daily usage, effectively limiting deliveries (or injections) to a customer's Bank to 20% of the customer's daily usage. The maximum amount of gas that can be stored in a Bank is referred to as the Bank Limit. A transportation customer's Bank Limit is equal to ten times the customer's highest average daily metered use during the 12-month period prior to the current billing period. Excess Bank is defined as the amount in therms of the Customer's positive balance in excess of the Customer's Bank Limit. Transportation customers are assessed a per therm penalty for all Excess Bank therms on a daily basis.
>
> Rider T requires transportation customers to supply 100% of their daily usage through deliveries of customer-owned gas and use of Bank. Transportation customers must deliver at least 80% of their daily usage to the Company's

> system. Use of Bank gas is restricted to 20% of the customer's daily usage. If, on any day, the customer fails to supply 100% of its daily usage through Bank withdrawals and/or deliveries subject to the limitations above, the customer is required to purchase System Gas from the Company to cover the shortfall. System Gas is defined as the portion of a transportation customer's daily use that is not transport volumes delivered to the Company or withdrawals of Bank or Excess Bank gas. (ICC Staff Exhibit 5.0, pp. 11-12.)

Mr. Iannello initially argued that the rules governing transportation customer deliveries and bank use were too strict relative to the storage costs that the Companies originally proposed to allocate to transportation customers. Mr. Iannello recommended changes to the maximum allowable Bank withdrawal and delivery requirements in Rider T. In addition, he recommended that the Companies reconcile the Bank Limit in Rider T with their storage cost allocations and allocation of other resources that allow the Companies to offer banking services. (Id., p. 15.) MEC witness Jansen recommends the elimination of the maximum allowable Bank withdrawal limitations except on critical days. (MEC Exhibit A, p. 7) He also recommends a "waiver of daily imbalances if the customer's daily imbalance is in the opposite direction of the Ameren CIPS net system imbalance." (MEC Exhibit A, p. 6.) BEAR witness Smith recommended eliminating restrictions on Bank use. In addition, Ms. Smith recommended that the Companies be required to establish "a reasonable cash-out mechanism." (BEAR Exhibit 1, p. 12.)

In response to concerns over the limitations on deliveries and Bank use in Rider T, CIPS proposed to develop a separate set of delivery rates for transportation customers and allocate less storage costs to transportation customers. This reallocation presumably reflects the inferior access to storage that transportation customers receive relative to sales customers. Although concerned that transportation customers may want greater flexibility to meet their daily demand through a combination of deliveries and Bank withdrawals and may be willing to pay for such flexibility, Mr. Iannello accepted CIPS' proposed reallocation of storage costs as an alternative to his revised delivery requirements and bank withdrawal limitations. (ICC Staff Exhibit 12.0, p. 10.) MEC and BEAR did not change their positions on the treatment of imbalances, the cash-out mechanism, and limitations on bank withdrawals in response to CIPS' reallocations of storage plant and related expenses.

Mr. Iannello summarized his position on the inter-related issues of storage cost allocation, limitations on deliveries and Bank withdrawals, and the implementation of a group balancing as follows:

> I continue to be concerned that the Company's proposed limitations on deliveries and Bank withdrawals discriminate against customers with loads that fluctuate unpredictably on a day-to-day basis, whereas the Company's sales service tariffs do not discriminate against such customers. However, my concerns are allayed by the fact that, under the Company's revised proposal, transportation customers will pay less for storage, and suppliers will have the opportunity to group customer accounts to ease the burden of meeting the Company's more strict delivery requirements and withdrawal limits. If transportation customers find that the Company's proposed delivery requirements and Bank withdrawal limitations are not workable, the Commission may need to revisit the terms of the Company's Rider T and the Company's proposed storage cost allocation in the future. (ICC Staff Exhibit 12.0, p. 11.)

10. Cash-out Mechanism for Transportation Customers

See Staff discussion on this issue in Section VI.C.9., *supra*.

11. 15-Day Requirement for New Services

Staff recommends the Companies revise their existing tariff language to require them to install new services in 15 working days or less except under certain extenuating circumstances not under their control. (ICC Staff Exhibit 17.0 Revised, pp. 4-9 and 28.) The Companies dispute the need for this provision.

Staff has three reasons for selecting the 15 working day time limit. First, Staff indicates that the 15 working days should provide the Companies enough time to receive the service request, schedule the work, and complete the installation without undue haste. (ICC Staff Exhibit 4.0, p. 10.) Second, Staff notes that the Companies had recently indicated they intended to reduce staffing through an early retirement program. (Id.) Staff considered the addition of the 15-day limit for installing new services as assurance that any future resource reductions would not cause service deterioration to the Companies' customers. (Id.) Finally, Staff notes as a matter of consistent policy that Staff recommended the same 15-day limit on new service installations for CILCO in Docket No. 02-0837. (Id.)

The Companies, in rebuttal testimony, provided several reasons why they opposed Staff's recommendation. (AmerenCIPS/UE Exhibit No. 11R, pp. 15-17.) Namely the Companies stated that:

1. Ameren is not aware of any problem that requires the proposed time limit;
2. Staff's proposed language does not take into account extenuating circumstances beyond the control of Ameren;
3. Staff's proposed language may hamper Ameren's ability to efficiently and effectively schedule work that needs accomplished;
4. Ameren's work force reductions do not impact people that install services; and
5. Ameren is concerned whether a rate case is the appropriate venue for this topic. (ICC Staff Exhibit 17.0 Revised, pp 4-5.)

Staff, in its rebuttal testimony, fully addressed each of the concerns raised by the Companies. In particular, Staff noted that it agreed with the statement that there does not currently exist a problem that requires this proposed tariff language change. However, Staff noted the institution of the 15-day new service installation time limit is a proactive step that will help ensure that the Companies do not cause service deterioration with the resource reductions. (Id., p. 5.)

The Companies' second concern dealt with the lack of any language to account for extenuating circumstances beyond the control of the Companies. Staff addressed this concern by adding language to the proposed tariff revision that allowed the Companies to exceed 15 working days if specialized equipment was necessary to install or provide service or if events such as work stoppages, insurrection, acts of terrorism, or other calamities require the Companies' resources be directed elsewhere. (Id., pp. 5-6.)

Staff disputes the Companies' third concern, wherein they stated the proposed language might hamper their ability to efficiently and effectively schedule work that needs to be accomplished. In particular, Staff noted that the Companies should be as efficient as their sister company – CILCO. (Id. p. 6.) CILCO had indicated that for the period 2000 through 2002, it had fulfilled 95% of the new customer requests within 15 working days. (Id.) Further, CILCO was able to meet this standard of service even though those percentages include all installations where specialized equipment needs or other circumstances where it would be allowed to exceed the 15 working day limit occurred. (Id.) The Companies did not counter Staff's statement, but merely stated that they were unable to provide an estimate of the percentage of customers that received new service installations in 15-working days. (AmerenCIPS/UE Exhibit No. 24.2.) Therefore, Staff considered very little, if any, of the Companies' existing work practices would require alteration if the Commission accepts Staff's proposed 15-day time limit for new service installations. (Id., p. 6-7.)

Regarding the Companies' comment that the early retirement offering did not impact employees who install services, Staff notes that the early retirement offering was not proffered to those employees who are involved in new service installations, therefore, it was impossible for any of those employees to take early retirement. (Id., p. 7.) However, given the early retirement offering that was made to the Companies' other employees, it is possible the employees used to install new services could also be reduced in the future, either through an early retirement offering, layoff, or through attrition. (Id.) Therefore, Staff continues to consider potential workforce reductions that could impact the amount of time the Companies take to install new services as a valid concern and as support for adding the tariff language.

The Companies' final concern was whether a rate case is the appropriate venue for considering Staff's proposal to institute a time limit on how long the Companies have to install a new service under certain circumstances. Staff disputes the Companies' assertion that a rate case may not be the appropriate venue. The Companies had ample opportunity to raise any concerns they had regarding the proposal as well as the proposed language selected by Staff in rebuttal and surrebuttal testimony. In fact, the Companies failed to provide any alternative language to Staff's proposal. (Tr., p. 569.)

The Companies' surrebuttal testimony did not dispute any of the language changes suggested by Staff, but it did raise one additional area of concern. Namely, the Companies' indicated that if the tariff provision is added, the potential exists for additional costs upon the Companies. In particular, the Companies noted some of the additional costs would include various computer programming and administrative costs that would be involved to show the Companies complied with the tariff requirement. (AmerenCIPS/UE Exhibit No. 24.0, p. 5.) However, the Companies did not provide any estimates for these costs nor did they state the Companies would have to hire additional computer programmers or administrators to comply with this requirement. Therefore, Staff concludes the costs identified above are minimal.

The Companies also speculate that they could incur a considerable labor expense if they had to add any employees to ensure compliance with the proposed tariff language. (Id.) In particular, the Companies note the addition of a single employee would increase costs by more than $50,000 per year. (Id.) However, the Companies were unable to state that any additional employees would be needed to comply with Staff's proposed language or that it current workforce in insufficient to meet the tariff requirements. The Companies' statement is pure speculation and should not be given any weight in determining this matter.

Staff's proposal to add tariff language that would require the Companies to install new service requests within 15 working days under certain circumstances is in the best interests of the Companies' customers. Staff's proposal addressed all of the various concerns raised by the Companies about the proposed tariff language and is a proactive step in assuring the Companies' customers do not see any deterioration in their service quality. Therefore, the Commission should require AmerenUE to alter its tariff's Terms and Conditions under Installation of Service, 1st Revised Sheet No. 11, and require AmerenCIPS to alter its tariff's Terms and Conditions under Installation of Service, Original Sheet No. 10.002, by adding the following language:

> The Company shall provide service connections to new customers within 15 working days at the requested location after being notified by the party who completed the service application request that property grading is in place, any obstructions or construction materials are removed, the location for the meter installation is prepared, and the Company determines a distribution main extension is not necessary in order to provide service. The 15-day time limit does not apply for those instances where specialized equipment is necessary for or to install the service connection or in the event of work stoppages, insurrection, acts of terrorism, or other calamities that require the Company's resources be directed elsewhere.

VII. CONCLUSION

For the reasons set forth above, Staff respectfully requests that the Commission's Order reflect Staff's modifications to the Companies' proposed general increase in natural gas rates as presented in Appendices A and B attached hereto.

Respectfully submitted,

SMatrisch

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July 28, 2003

AmerenCIPS
Statement of Operating Income with Adjustments
For the Test Year Ending June 30, 2002
(In Thousands)

Line No.	Description	Company Rebuttal Pro Forma Present (St. Ex. 18.0 Sch. 18.1 CIPS, p. 2)	Staff Adjustments (Appendix A Sch. 2)	Staff Pro Forma Present (Cols. B+C)	Company Proposed Increase (Co. Schs. C-1, C-6.2)	Staff Gross Revenue Conversion Factor	Proposed Rates With Staff Adjustments (Cols. D+E+F)	Adjustment To Proposed Increase	Staff Pro Forma Proposed (Cols. G+H)
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	Operating Revenues	$ 52,831	$ -	$ 52,831	$ 16,395	$ (56)	$ 69,170	$ (8,483)	$ 60,687
2	Other Revenues	1,351	-	1,351	-	-	1,351	-	1,351
3	PGA Revenues	86,819	-	86,819	-	-	86,819	-	86,819
4		-	-	-	-	-	-	-	-
5	Total Operating Revenue	141,001	-	141,001	16,395	(56)	157,340	(8,483)	148,857
6	Uncollectible Accounts	1,442	(453)	989	164	(56)	1,097	(56)	1,041
7	Production	964	(90)	874	-	-	874	-	874
8	PGA Expenses	86,819	-	86,819	-	-	86,819	-	86,819
9	Gas Storage and Processing	1,653	(29)	1,624	-	-	1,624	-	1,624
10	Transmission	960	(31)	929	-	-	929	-	929
11	Distribution	13,121	(472)	12,649	-	-	12,649	-	12,649
12	Customer Accounts	2,596	(89)	2,507	-	-	2,507	-	2,507
13	Customer Service	122	(11)	111	-	-	111	-	111
14	Sales	178	(7)	171	-	-	171	-	171
15	Administrative and General	15,242	(1,307)	13,935	-	-	13,935	-	13,935
16	Depreciation and Amortization	7,358	(5)	7,353	-	-	7,353	-	7,353
17	Taxes Other Than Income	2,172	(64)	2,108	-	-	2,108	-	2,108
18		-	-	-	-	-	-	-	-
19	Total Operating Expense								
20	Before Income Taxes	132,627	(2,558)	130,069	164	(56)	130,177	(56)	130,121
21	State Income Tax	298	69	367	1,185	-	1,552	(615)	937
22	Federal Income Tax	905	729	1,634	5,266	-	6,900	(2,734)	4,166
23	Deferred Invest. Tax Credits - Net	(162)	-	(162)	-	-	(162)	-	(162)
24	Total Operating Expenses	133,668	(1,760)	131,908	6,615	(56)	138,467	(3,405)	135,062
25	NET OPERATING INCOME	$ 7,333	$ 1,760	$ 9,093	$ 9,780	$ -	$ 18,873	$ (5,078)	$ 13,795
26	Staff Rate Base (Appendix A, Schedule 3, Column (D))								$ 166,409
27	Staff Overall Rate of Return (ICC Staff Exhibit 6.0, Schedule 6.1 CIPS)								8.29%
28	Revenue Change (Col. (I) Line 1 minus Col. (D), Line 1)								$ 7,856
29	Percentage Revenue Change (Col. (I), Line 28 divided by Col. (D), Line 5)								5.57%

AmerenCIPS
Adjustments to Operating Income
For the Test Year Ending June 30, 2002
(In Thousands)

Line No.	Description	Interest Synchronization (St. Ex. 18.0 Sch. 18.5 CIPS)	Outside Services (St. Ex. 18.0 Sch. 18.7 CIPS)	Rate Case Expense (St. Ex. 18.0 Sch. 18.8 CIPS)	Wage Expense (St. Ex. 18.0 Sch. 18.9 CIPS)	Pension Expense (St. Ex. 18.0 Sch. 18.10 CIPS)	Incentive Compensation (St. Ex. 18.0 Sch. 18.11 CIPS)	Early Retirement (Appendix A Sch. 6)	Subtotal Operating Statement Adjustments
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3	PGA Revenues	-	-	-	-	-	-	-	-
4		-	-	-	-	-	-	-	-
5	Total Operating Revenue	-	-	-	-	-	-	-	-
6	Uncollectible Accounts	-	-	-	-	-	-	-	-
7	Production	-	-	-	-	-	(88)	(2)	(90)
8	PGA Expenses	-	-	-	-	-	-	-	-
9	Gas Storage and Processing	-	-	-	(9)	-	(14)	(2)	(25)
10	Transmission	-	-	-	(4)	-	(25)	(2)	(31)
11	Distribution	-	-	-	(185)	-	(257)	(30)	(472)
12	Customer Accounts	-	-	-	(43)	-	(40)	(6)	(89)
13	Customer Service	-	-	-	-	-	(6)	-	(6)
14	Sales	-	-	-	-	-	(7)	-	(7)
15	Administrative and General	-	-	(41)	(13)	-	(97)	(6)	(157)
16	Depreciation and Amortization	-	-	-	-	-	-	-	-
17	Taxes Other Than Income	-	-	-	(19)	-	(41)	(4)	(64)
18		-	-	-	-	-	-	-	-
19	Total Operating Expense								
20	Before Income Taxes	-	-	(41)	(273)	-	(575)	(52)	(941)
21	State Income Tax	1	-	3	20	-	42	4	70
22	Federal Income Tax	6	-	13	89	-	187	17	312
23	Deferred Invest. Tax Credits - Net	-	-	-	-	-	-	-	-
24	Total Operating Expenses	7	-	(25)	(164)	-	(346)	(31)	(559)
25	NET OPERATING INCOME	$ (7)	$ -	$ 25	$ 164	$ -	$ 346	$ 31	$ 559

AmerenCIPS

Adjustments to Operating Income

For the Test Year Ending June 30, 2002

(In Thousands)

Line No.	Description	Subtotal Operating Statement Adjustments	Voluntary Retirement Program Costs (St. Ex. 18.0 Sch. 18.13 CIPS)	Uncollectibles Expense (St. Ex. 10.0 Sch. 10.3 CIPS)	Advertising Expense (St. Ex. 10.0 Sch. 10.4 CIPS)	Charitable Contributions (St. Ex. 10.0 Sch. 10.5 CIPS)	Membership Dues (St. Ex. 10.0 Sch. 10.6 CIPS)	Interest on Customer Deposits (St. Ex. 10.0 Sch. 10.7 CIPS)	Subtotal Operating Statement Adjustments
	(A)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
1	Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3	PGA Revenues	-	-	-	-	-	-	-	-
4		-	-	-	-	-	-	-	-
5	Total Operating Revenue	-	-	-	-	-	-	-	-
6	Uncollectible Accounts	-	-	(453)	-	-	-	-	(453)
7	Production	(90)	-	-	-	-	-	-	(90)
8	PGA Expenses	-	-	-	-	-	-	-	-
9	Gas Storage and Processing	(25)	-	-	-	-	-	-	(25)
10	Transmission	(31)	-	-	-	-	-	-	(31)
11	Distribution	(472)	-	-	-	-	-	-	(472)
12	Customer Accounts	(89)	-	-	-	-	-	-	(89)
13	Customer Service	(6)	-	-	(5)	-	-	-	(11)
14	Sales	(7)	-	-	-	-	-	-	(7)
15	Administrative and General	(157)	(1,150)	-	-	-	-	-	(1,307)
16	Depreciation and Amortization	-	-	-	-	-	-	-	-
17	Taxes Other Than Income	(64)	-	-	-	-	-	-	(64)
18		-	-	-	-	-	-	-	-
19	Total Operating Expense								
20	Before Income Taxes	(941)	(1,150)	(453)	(5)	-	-	-	(2,549)
21	State Income Tax	70	84	33	-	-	-	-	187
22	Federal Income Tax	312	373	147	2	-	-	-	834
23	Deferred Invest. Tax Credits - Net	-	-	-	-	-	-	-	-
24	Total Operating Expenses	(559)	(693)	(273)	(3)	-	-	-	(1,528)
25	NET OPERATING INCOME	$ 559	$ 693	$ 273	$ 3	$ -	$ -	$ -	$ 1,528

AmerenCIPS
Adjustments to Operating Income
For the Test Year Ending June 30, 2002
(In Thousands)

Line No.	Description	Subtotal Operating Statement Adjustments	Income Tax Expense (St. Ex. 10.0 Sch. 10.8 CIPS)	Belle Gent Storage Field (St. Ex. 16.0 Sch. 16.2 CIPS)	(Source)	(Source)	(Source)	(Source)	Total Operating Statement Adjustments
	(A)	(R)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)
1	Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3	PGA Revenues	-	-	-	-	-	-	-	-
4		-	-	-	-	-	-	-	-
5	Total Operating Revenue	-	-	-	-	-	-	-	-
6	Uncollectible Accounts	(453)	-	-	-	-	-	-	(453)
7	Production	(90)	-	-	-	-	-	-	(90)
8	PGA Expenses	-	-	-	-	-	-	-	-
9	Gas Storage and Processing	(25)	-	(4)	-	-	-	-	(29)
10	Transmission	(31)	-	-	-	-	-	-	(31)
11	Distribution	(472)	-	-	-	-	-	-	(472)
12	Customer Accounts	(89)	-	-	-	-	-	-	(89)
13	Customer Service	(11)	-	-	-	-	-	-	(11)
14	Sales	(7)	-	-	-	-	-	-	(7)
15	Administrative and General	(1,307)	-	-	-	-	-	-	(1,307)
16	Depreciation and Amortization	-	-	(5)	-	-	-	-	(5)
17	Taxes Other Than Income	(64)	-	-	-	-	-	-	(64)
18		-	-	-	-	-	-	-	-
19	Total Operating Expense								
20	Before Income Taxes	(2,549)	-	(9)	-	-	-	-	(2,558)
21	State Income Tax	187	(119)	1	-	-	-	-	69
22	Federal Income Tax	834	(108)	3	-	-	-	-	729
23	Deferred Invest. Tax Credits - Net	-	-	-	-	-	-	-	-
24	Total Operating Expenses	(1,528)	(227)	(5)	-	-	-	-	(1,760)
25	NET OPERATING INCOME	$ 1,528	$ 227	$ 5	$ -	$ -	$ -	$ -	$ 1,760

AmerenCIPS

Rate Base

For the Test Year Ending June 30, 2002
(In Thousands)

Line No.	Description	Company Rebuttal Pro Forma Rate Base (St. Ex. 18.0 Sch. 18.3 CIPS, p. 2)	Staff Adjustments (Appendix A Sch. 4)	Staff Pro Forma Rate Base (Col. B+C)
	(A)	(B)	(C)	(D)
1	Gross Plant in Service	$ 299,201	$ (127)	$ 299,074
2	Accumulated Depreciation	(137,601)	185	(137,416)
3		-	-	-
4	Net Plant	161,600	58	161,658
5	Additions to Rate Base			
6	Materials & Supplies	1,063	-	1,063
7	Gas Stored Underground & Propane	26,979	(842)	26,137
8	Cash Working Capital	7,386	(7,386)	-
9	Deferred Info System Development	102	-	102
10		-	-	-
11		-	-	-
12		-	-	-
13		-	-	-
14		-	-	-
15		-	-	-
16	Deductions From Rate Base		-	
17	Customer Advances	(717)	-	(717)
18	Customer Deposits	(688)	-	(688)
19	Pre-1971 Investment Tax Credits	(2)	-	(2)
20	Accumulated Deferred Income Taxes	(21,144)	-	(21,144)
21		-	-	-
22		-	-	-
23	Rate Base	$ 174,579	$ (8,170)	$ 166,409

AmerenCIPS
Adjustments to Rate Base
For the Test Year Ending June 30, 2002
(In Thousands)

Line No.	Description	Cash Working Capital (St. Ex. 10.0 Sch. 10.1 CIPS)	Material & Supplies (St. Ex. 10.0 Sch. 10.2 CIPS)	Customer Deposits (St. Ex. 10.0 Sch. 10.7 CIPS)	Underground Storage (St. Ex. 17.0 Sch. 17.1 CIPS)	Plant Held for Future Use (St. Ex. 16.0 Sch. 16.1)	Belle Gent Storage Field (St. Ex. 16.0 Sch. 16.2)	Richwood Storage Field (St. Ex. 16.0 Sch. 16.3)	Total Rate Base Adjustments
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	Gross Plant in Service	$ -	$ -	$ -	$ -	$ -	$ (127)	$ -	$ (127)
2	Accumulated Depreciation	-	-	-	-	-	127	58	185
3	-	-	-	-	-	-	-	-	-
4	Net Plant	-	-	-	-	-	-	58	58
	-								
5	Additions to Rate Base								
6	Materials & Supplies	-	-	-	-	-	-	-	-
7	Gas Stored Underground & Propane	-	-	-	(842)	-	-	-	(842)
8	Cash Working Capital	(7,386)	-	-	-	-	-	-	(7,386)
9	Deferred Info System Developmen	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-
16	Deductions From Rate Base	-	-	-	-	-	-	-	-
17	Customer Advances	-	-	-	-	-	-	-	-
18	Customer Deposits	-	-	-	-	-	-	-	-
19	Pre-1971 Investment Tax Credits	-	-	-	-	-	-	-	-
20	Accumulated Deferred Income Taxes	-	-	-	-	-	-	-	-
21	-	-	-	-	-	-	-	-	-
22	-	-	-	-	-	-	-	-	-
23	Rate Base	$ (7,386)	$ -	$ -	$ (842)	$ -	$ -	$ 58	$ (8,170)

AmerenCIPS

Gross Revenue Conversion Factor

For the Test Year Ending June 30, 2002

(In Thousands)

Line No.	Description	Rate	Per Staff With Bad Debts	Per Staff Without Bad Debts
	(A)	(B)	(C)	(D)
1	Revenues		1.000000	
2	Uncollectibles	0.6600%	0.006600	
3	State Taxable Income		0.993400	1.000000
4	State Income Tax	7.3000%	0.072518	0.073000
5	Federal Taxable Income		0.920882	0.927000
6	Federal Income Tax	35.0000%	0.322309	0.324450
7	Operating Income		0.598573	0.602550
8	Gross Revenue Conversion Factor Per Staff		1.670640	1.659613

Central Illinois Public Service Company
Early Retirement Labor Expense Adjustment
For the Test Year Ending June 30, 2002
(In Thousands)

				Labor Expense for Backfill Positions		Staff Adjustments	
Line No.	Description	Annualized 2002 Labor	% of Total	Per Staff	Per Company	Labor Expense (E-F)	Associated Payroll Tax (G*7.65%)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	Gas O & M						
2	Production	$ 512	4%	$ 6	$ 8	$ (2)	
3	Storage	472	3%	6	7	(2)	
4	Transmission	525	4%	6	8	(2)	
5	Distribution	9,141	63%	107	137	(30)	
6	Cust. Accounts	1,776	12%	21	27	(6)	
7	Customer Service	99	1%	1	1	(0)	
8	Sales	125	1%	1	2	(0)	
9	Admin. & General	1,960	13%	23	29	(6)	
10	Total	$ 14,610	100%	$ 171	$ 219	$ (48)	$ (4)

Source:

Col. C	CIPS workpaper WPC-3.7a, col f.
Col. D	Column C/Total Column C.
Col. E, line 10	AmerenCIPS/UE Exhibit No. 27.1.
Col. E, lines 2-9	Column D x Column E, line 10.
Col. F	AmerenCIPS Ex. No. 27.7, line 7.

Docket Nos. 02-0837/03-0008/
03-0009 (Consolidated)
Appendix B
Schedule 1

AmerenUE

Statement of Operating Income with Adjustments

For the Test Year Ending June 30, 2002

(In Thousands)

Line No.	Description	Company Rebuttal Pro Forma Present (St. Ex. 18.0 Sch. 18.1 UE, p. 2)	Staff Adjustments (Appendix B Sch. 2)	Staff Pro Forma Present (Cols. B+C)	Company Proposed Increase (Co. Schs. C-1, C-6.2)	Staff Gross Revenue Conversion Factor	Proposed Rates With Staff Adjustments (Cols. D+E+F)	Adjustment To Proposed Increase	Staff Pro Forma Proposed (Cols. G+H)
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	Operating Revenues	$ 4,960	$ -	$ 4,960	$ 3,772	$ 684	$ 9,416	$ (2,159)	$ 7,257
2	Other Revenues	174	-	174	-	-	174	-	174
3	PGA Revenues	9,852	-	9,852	-	-	9,852	-	9,852
4		-	-	-	-	-	-	-	-
5	Total Operating Revenue	14,986	-	14,986	3,772	684	19,442	(2,159)	17,283
6	Uncollectible Accounts	399	(297)	102	74	(41)	135	(16)	119
7	Production	232	(25)	207	-	-	207	-	207
8	PGA Expenses	9,852	-	9,852	-	-	9,852	-	9,852
9	Gas Storage and Processing	-	-	-	-	-	-	-	-
10	Transmission	50	(1)	49	-	-	49	-	49
11	Distribution	1,474	(55)	1,419	-	-	1,419	-	1,419
12	Customer Accounts	669	(13)	656	-	-	656	-	656
13	Customer Service	102	(5)	97	-	-	97	-	97
14	Sales	11	(1)	10	-	-	10	-	10
15	Administrative and General	2,389	(175)	2,214	-	-	2,214	-	2,214
16	Depreciation and Amortization	756	-	756	-	-	756	-	756
17	Taxes Other Than Income	168	(9)	159	-	-	159	-	159
18		-	-	-	-	-	-	-	-
19	Total Operating Expense								
20	Before Income Taxes	16,102	(581)	15,521	74	(41)	15,554	(16)	15,538
21	State Income Tax	(1)	(74)	(75)	190	133	248	(156)	92
22	Federal Income Tax	(210)	(163)	(373)	843	592	1,062	(695)	367
23	ITCs	(16)	-	(16)	-	-	(16)	-	(16)
24	Total Operating Expenses	15,875	(818)	15,057	1,107	684	16,848	(867)	15,981
25	NET OPERATING INCOME	$ (889)	$ 818	$ (71)	$ 2,665	$ -	$ 2,594	$ (1,292)	$ 1,302
26	Staff Rate Base (Appendix B, Schedule 3, Column (D))								$ 15,908
27	Staff Overall Rate of Return (ICC Staff Exhibit 13.0, Schedule 13.1 UE)								8.19%
28	Revenue Change (Col. (I) Line 1 minus Col. (D), Line 1)								$ 2,297
29	Percentage Revenue Change (Col. (I), Line 28 divided by Col. (D), Line 5)								15.33%

AmerenUE
Adjustments to Operating Income
For the Test Year Ending June 30, 2002
(In Thousands)

Line No.	Description	Interest Synchronization (St. Ex. 18.0 Sch. 18.5 UE)	Outside Services (St. Ex. 18.0 Sch. 18.7 UE)	Rate Case Expense (St. Ex. 18.0 Sch. 18.8 UE)	Wage Expense (St. Ex. 18.0 Sch. 18.9 UE)	Pension Expense (St. Ex. 18.0 Sch. 18.10 UE)	Incentive Compensation (St. Ex. 18.0 Sch. 18.11 UE)	Early Retirement (Appendix B Sch. 6)	Subtotal Operating Statement Adjustments
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3	PGA Revenues	-	-	-	-	-	-	-	-
4		-	-	-	-	-	-	-	-
5	Total Operating Revenue	-	-	-	-	-	-	-	-
6	Uncollectible Accounts	-	-	-	-	-	-	-	-
7	Production	-	-	-	-	-	(24)	(1)	(25)
8	PGA Expenses	-	-	-	-	-	-	-	-
9	Gas Storage and Processing	-	-	-	-	-	-	-	-
10	Transmission	-	-	-	-	-	(1)	-	(1)
11	Distribution	-	-	-	(26)	-	(26)	(3)	(55)
12	Customer Accounts	-	-	-	(6)	-	(6)	(1)	(13)
13	Customer Service	-	-	-	(2)	-	(2)	-	(4)
14	Sales	-	-	-	(1)	-	-	-	(1)
15	Administrative and General	-	-	(32)	(3)	-	(17)	(1)	(53)
16	Depreciation and Amortization	-	-	-	-	-	-	-	-
17	Taxes Other Than Income	-	-	-	(3)	-	(6)	-	(9)
18		-	-	-	-	-	-	-	-
19	Total Operating Expense								
20	Before Income Taxes	-	-	(32)	(41)	-	(82)	(6)	(161)
21	State Income Tax	(3)	-	2	3	-	6	-	8
22	Federal Income Tax	(14)	-	10	13	-	27	2	38
23	ITCs	-	-	-	-	-	-	-	-
24	Total Operating Expenses	(17)	-	(20)	(25)	-	(49)	(4)	(115)
25	NET OPERATING INCOME	$ 17	$ -	$ 20	$ 25	$ -	$ 49	$ 4	$ 115

AmerenUE

Adjustments to Operating Income

For the Test Year Ending June 30, 2002

(In Thousands)

Line No.	Description	Subtotal Operating Statement Adjustments	Voluntary Retirement Program Costs (St. Ex. 18.0 Sch. 18.13 UE)	Uncollectibles Expense (St. Ex. 10.0 Sch. 10.3UE)	Advertising Expense (St. Ex. 10.0 Sch. 10.4 UE)	Income Tax Expense (St. Ex. 10.0 Sch. 10.8UE)	Automated Meter Reading Expense (Adjustment withdrawn)	(Source)	Total Operating Statement Adjustments
	(A)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
1	Operating Revenues	$ -		$ -	$ -			$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3	PGA Revenues	-	-	-	-	-	-	-	-
4		-	-	-	-	-	-	-	-
5	Total Operating Revenue	-	-	-	-	-	-	-	-
6	Uncollectible Accounts	-	-	(297)	-	-	-	-	(297)
7	Production	(25)	-	-	-	-	-	-	(25)
8	PGA Expenses	-	-	-	-	-	-	-	-
9	Gas Storage and Processing	-	-	-	-	-	-	-	-
10	Transmission	(1)	-	-	-	-	-	-	(1)
11	Distribution	(55)	-	-	-	-		-	(55)
12	Customer Accounts	(13)	-	-	-	-	-	-	(13)
13	Customer Service	(4)	-	-	(1)	-	-	-	(5)
14	Sales	(1)	-	-	-	-	-	-	(1)
15	Administrative and General	(53)	(122)	-	-	-	-	-	(175)
16	Depreciation and Amortization	-	-	-	-	-	-	-	-
17	Taxes Other Than Income	(9)	-	-	-	-	-	-	(9)
18		-	-	-	-	-	-	-	-
19	Total Operating Expense								
20	Before Income Taxes	(161)	(122)	(297)	(1)	-	-	-	(581)
21	State Income Tax	8	9	22	-	(113)	-	-	(74)
22	Federal Income Tax	38	40	96	-	(337)	-	-	(163)
23	ITCs	-	-	-	-	-	-	-	-
24	Total Operating Expenses	(115)	(73)	(179)	(1)	(450)	-	-	(818)
25	NET OPERATING INCOME	$ 115	$ 73	$ 179	$ 1	$ 450	$ -	$ -	$ 818

Docket Nos. 02-0837/03-0008/
03-0009 (Consolidated)
Appendix B
Schedule 3

AmerenUE
Rate Base
For the Test Year Ending June 30, 2002
(In Thousands)

Line No.	Description	Company Rebuttal Pro Forma Rate Base (St. Ex. 18.0 Sch. 18.3 UE, p. 2)	Staff Adjustments (St. Ex. 18.0 Sch. 18.4 UE)	Staff Pro Forma Rate Base (Col. B+C)
	(A)	(B)	(C)	(D)
1	Gross Plant in Service	$ 32,088	$ -	$ 32,088
2	Accumulated Depreciation	(15,977)	-	(15,977)
3		-	-	-
4	Net Plant	16,111	-	16,111
5	Additions to Rate Base			
6	Materials & Supplies	36	-	36
7	Gas Stored Underground & Propane	1,703	(2)	1,701
8	Cash Working Capital	840	(840)	-
9	Deferred Info System Development	-	-	-
10		-	-	-
11		-	-	-
12		-	-	-
13		-	-	-
14		-	-	-
15		-	-	-
16	Deductions From Rate Base			
17	Customer Advances	(147)	-	(147)
18	Customer Deposits	(46)	-	(46)
19	Pre-1971 Investment Tax Credits	(13)	-	(13)
20	Accumulated Deferred Income Taxes	(1,734)	-	(1,734)
21		-	-	-
22		-	-	-
23	Rate Base	$ 16,750	$ (842)	$ 15,908

Docket Nos. 02-0837/03-0008/
03-0009 (Consolidated)
Appendix B
Schedule 4

AmerenUE
Adjustments to Rate Base
For the Test Year Ending June 30, 2002
(In Thousands)

Line No.	Description	Cash Working Capital (St. Ex. 10.0 Sch. 10.1 UE)	Material & Supplies (St. Ex. 10.0 Sch. 10.2 UE)	Customer Deposits (St. Ex. 10.0 Sch. 10.7 UE)	Underground Storage (St. Ex. 11.0 Sch. 11.1 UE)	(Source)	(Source)	(Source)	Total Rate Base Adjustments
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	Gross Plant in Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Accumulated Depreciation	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-
4	Net Plant	-	-	-	-	-	-	-	-
	-								
5	Additions to Rate Base								
6	Materials & Supplies	-	-	-	-	-	-	-	-
7	Gas Stored Underground & Propane	-	-	-	(2)	-	-	-	(2)
8	Cash Working Capital	(840)	-	-	-	-	-	-	(840)
9	Deferred Info System Developmen	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-
16	Deductions From Rate Base	-	-	-	-	-	-	-	-
17	Customer Advances	-	-	-	-	-	-	-	-
18	Customer Deposits	-	-	-	-	-	-	-	-
19	Pre-1971 Investment Tax Credits	-	-	-	-	-	-	-	-
20	Accumulated Deferred Income Taxes	-	-	-	-	-	-	-	-
21	-	-	-	-	-	-	-	-	-
22	-	-	-	-	-	-	-	-	-
23	Rate Base	$ (840)	$ -	$ -	$ (2)	$ -	$ -	$ -	$ (842)

AmerenUE

Gross Revenue Conversion Factor

For the Test Year Ending June 30, 2002

(In Thousands)

Line No.	Description	Rate	Per Staff With Bad Debts	Per Staff Without Bad Debts
	(A)	(B)	(C)	(D)
1	Revenues		1.000000	
2	Uncollectibles	0.7500%	0.007500	
3	State Taxable Income		0.992500	1.000000
4	State Income Tax	7.3000%	0.072453	0.073000
5	Federal Taxable Income		0.920047	0.927000
6	Federal Income Tax	35.0000%	0.322016	0.324450
7	Operating Income		0.598031	0.602550
8	Gross Revenue Conversion Factor Per Staff		1.672154	1.659613

Docket Nos. 02-0837/03-0008/
03-0009 (Consolidated)
Appendix B
Schedule 6

Union Electric Company
Early Retirement Labor Expense Adjustment
For the Test Year Ending June 30, 2002
(In Thousands)

Line No. (A)	Description (B)	Annualized 2002 Labor (C)	% of Total (D)	Labor Expense for Backfill Positions: Per Staff (E)	Labor Expense for Backfill Positions: Per Company (F)	Staff Adjustments: Labor Expense (E-F) (G)	Staff Adjustments: Associated Payroll Tax (G*7.65%) (H)
1	Gas O & M						
2	Production	$ 118	6%	$ 1	$ 2	$ (1)	
3	Storage	-	0%	-	-	-	
4	Transmission	29	1%	-	-	-	
5	Distribution	1,187	56%	13	16	(3)	
6	Cust. Accounts	284	13%	3	4	(1)	
7	Customer Service	94	4%	1	1	-	
8	Sales	8	0%	-	-	-	
9	Admin. & General	411	19%	4	5	(1)	
10	Total	$ 2,131	100%	$ 22	$ 28	$ (6)	$ (0)

Source:

Col. C — UE workpaper WPC-3.7a, col f.
Col. D — Column C/Total Column C.
Col. E, line 10 — AmerenCIPS/UE Exhibit No. 27.1.
Col. E, lines 2-9 — Column D x Column E, line 10.
Col. F — AmerenUE Ex. No. 27.4, line 7.